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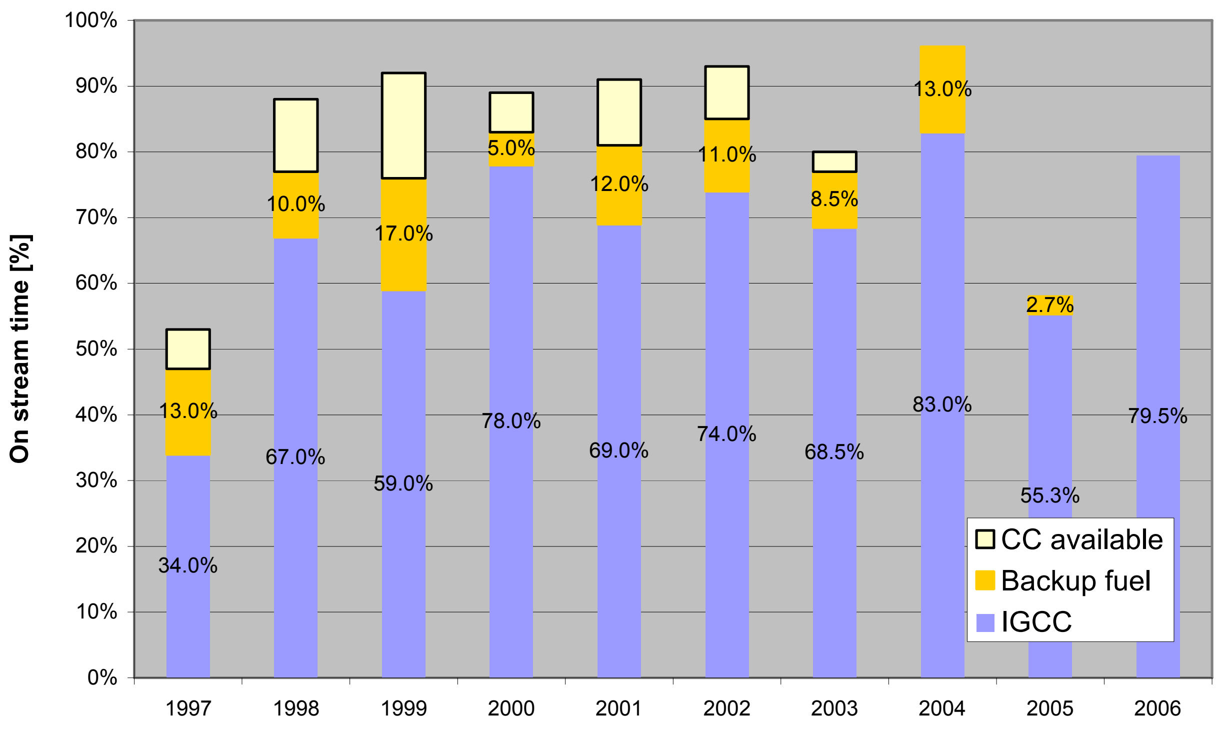
Integrated Gasification Combined Cycle (IGCC) Design Considerations for High Availability

Volume 1: Lessons from Existing Operations

1012226



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Technical Update, March 2007

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PRODUCT DESCRIPTION

This report analyses public domain availability data from Integrated Gasification Combined Cycles (IGCC) and other significant coal gasification facilities, backed up with additional data gained from interviews and discussions with plant operators. Predictions for the availability of future IGCCs are made based on the experience of the existing fleet and anticipated improvements from the implementation of lessons learned.

Results and Findings

Beginning in the mid-1990's, a number of IGCC plants were built and operated so that a base of experience has begun to develop. These plants have confirmed the exceptionally low (SOx, NOx, particulate matter and, if required, mercury) or less toxic (waste water and slag) emissions from this technology. They have also confirmed the expectations of improved thermal efficiency, even if parallel advances in other coal-based technologies have not allowed this to be translated into the competitive advantage originally contemplated.

However, the reliability and availability of demonstration IGCC's has not been as high as desired by the power industry or as actually achieved by gasification plants operating in the chemical and refining industries. The success of IGCC in realizing its potential is therefore also dependant on establishing the reasons for this reduced reliability and taking appropriate steps to improve it.

It is striking that much of the causes for reduced availability originate in areas where it could be assumed that the technology was established. The data for four IGCC units over the period 2001-2003 shows that on average the units were out of service 17.2% of the time due to issues with the combined cycle power block, 6.2% of the time due to the gasification equipment, 3.3% of the time due to issues with the air separation units, and 1.6% of the time due to gas treating equipment, for a total outage time of 28.2%. This corresponds to an average availability of 71.8%

Furthermore in the gasification area there is a mixture of issues which might have been avoidable and others that are inherent to the process (e.g. syngas cooling).

Based on the state of current technology, it is expected that an availability of at least 85% could be reached. An increase in the availability of gas turbines could increase this further to about 90%.

Challenges and Objectives

A simple "checklist" approach to the elimination of problems identified in existing plants is insufficient to achieve availability levels of 85 to 90%. It is necessary to include availability as a key objective of the project team from the inception. Key plant operations and maintenance personnel must be identified at an early stage and must be involved at every stage of the design. The design process must recognize the "chemical plant" nature of an IGCC and include many of the features common in the chemical industry (HAZOP, Process Safety Management etc.).

Applications, Values, and Use

The report will be a great value to any organization considering the deployment of IGCC technology. It is also of use to organizations considering the deployment of other advanced coal generation technologies who wish to conduct a "due diligence" review of the alternatives in order to defend their technology choice for a coal power plant.

EPRI Perspective

The CoalFleet IGCC RD&D Augmentation Plan (EPRI Technical Update 1013219 issued in Jan. 2007) identified improvement in IGCC availability as a key near-term RD&D task. The Augmentation Plan also called for more detailed quantification of the causes of IGCC unavailability as the first step in the plan to improve availability. One must first know what is causing the problem before a solution can be developed.

This report, the first of a two-part set which will address reliability-availability-maintainability (RAM) expectations for new IGCCs, fulfills the first step in the CoalFleet IGCC RAM improvement strategy. It compiles the availability experience of existing coal-based IGCCs and supplements that with relevant availability information from IGCCs designed for liquid petroleum residues and coal gasification plants which produce chemicals rather than power. EPRI believes it is the most comprehensive compilation of IGCC availability data ever assembled.

A companion report, being assembled by Strategic Power Systems, Inc. (SPS), will develop predictions for the reliability and availability of new IGCC designs based on a section-by-section model of the IGCC. The models rely on the database of availability information compiled in this first report as well as the extensive ORAP® database on combustion turbines and combined cycle maintained by SPS. The IGCC design reflect the standard configurations for a nominal 600 MW IGCC defined in the CoalFleet User Design Basis Specification – Version 4 (EPRI Technical Report 1012227 issued in Dec. 2006) for both GE Energy and Shell coal gasification technology.

Approach

Data were first gleaned from more than 90 reports or presentations on gasification plants available in the public domain. These reports are listed in the literature references section of this report. These data were supplemented by private interviews with gasification plant operations staff and plant visits to selected gasification facilities. The compiled data were then analyzed to identify underlying trends or cause of unavailability.

Keywords

Gasification
Coal
Reliability
Operations & maintenance
Operating experience

ACRONYMS

(Does not include chemical formulae or names of processes/companies.)

AGR	Acid gas removal
ASU	Air separation Unit
BOP	Balance of plant
CCU	Combined cycle unit
DGAN	Dilution gaseous nitrogen
GOX	Gaseous oxygen
GTC	Gasification Technologies Council
IGCC	Integrated gasification combined cycle
LIN	Liquid nitrogen
LNG	Liquefied natural gas
LOX	Liquid oxygen
NGCC	Natural gas combined cycle
SCR	Selective catalytic reduction (of NO_x)
SRU	Sulfur recovery unit
HRSG	Heat recovery steam generator

ACKNOWLEDGEMENTS

The information provided in this report could not have been assembled without the dedication and public spirit shown by the operators of the plants described who have put considerable time and effort into preparing information on the operation of their facilities and publishing it at conferences both in the US and internationally. Most of the individuals concerned are named in the list of references and thanks go to all of them for their work. Additional information has been derived from discussions with some of these authors in correspondence, discussions and plant visits, which has proved invaluable in interpreting the published data. These include:

Carlo Wolters and Marco Kanaar, Nuon Power Buggenum
Cliff Keeler, ConocoPhillips (formerly Wabash River Energy Ltd.)
John McDaniel and Mark Hornick, TECO Polk Power Station
Francisco Garcia Peña, Elcogas, Puertollano
Claudio Allevi, Sarlux
Bill Trapp and Nate Mook, Eastman Chemical, Kingsport
Neal Barkley, Coffeyville Resources
Monica Mais, api Raffineria di Ancona
Francesco Tufaro, Alstom Power Italia S.p.A

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 INTRODUCTION

Objectives

In discussions which took place with various people inside and outside the gasification industry during the last two or three years, it became clear that there were many misperceptions concerning the availability (or lack thereof) of gasification plants generally and IGCCs in particular. Much out-of-date information was still in circulation and despite a great deal of material published by plant operators, there was little understanding of the root causes of plant outage time. EPRI therefore decided to commission a report on the availability performance of the existing (1990's) generation of IGCC power plant and the conclusions that can be drawn for a new generation of plants to come into service in the 2010-2014 time frame.[Higman, 2006]

This report draws largely on public domain data or data provided to EPRI by plant operators. Much of this has been backed up by interviews and discussions with personnel in the plants to ensure that interpretation of the data is correct.

It should be emphasized that while average expected numbers will be developed for availability, the number of plants in existence (14 plants worldwide operating gas turbines on syngas) does not provide a broad enough basis for scientifically meaningful statistics. Nonetheless there is sufficient information available to develop an understanding of problems that have already been solved, others that are on-going and even in part to identify areas for potentially new problems. Most importantly it generates a list of lessons learned, which can aid a potential project developer to identify risks and build suitable mitigation strategies into his project implementation scheme.

Background

The concept of generating electricity by gasifying coal and using the synthesis gas (syngas) as fuel in a gas turbine is not new. Already in 1950 Wilhelm Gumz described such a suggestion in his book, "Gas Producers and Blast Furnaces". However 20 years were to pass before this idea was actually put into it practice at a commercial scale. The first three plants are summarized in Table 1-1.

Table 1-1
First Prototype IGCC Power Plants

Location	Gasifier type	Gas turbine	Start up date	MW_e	Efficiency (LHV)
Lünen, Germany	**Sasol-Lurgi [1] moving bed**	**Siemens V93**	**1969/1972**	**170**	**31.7%**
Cool Water, CA	**GEE with radiant cooler**	**GE 107E**	**1984**	**100**	**31.2%**
Plaquemine, LA	**E-Gas**	**Westinghouse W501D5**	**1987**	**160**	**36.0%**

These three plants can be classified as prototypes and the experience gained with them will not be described here. More important is that this experience flowed into the next generation of 250-300 MW_e plants, which were all put into service in the 1990's. The Tampa Electric Polk unit is based on the Cool Water concept with a GEE radiant cooler configuration gasifier and a GE 7FA gas turbine. Wabash has an E-Gas gasifier as in Plaquemine. The experience gained in Lünen with syngas in the Siemens V93 gas turbine was available for the machines for Buggenum (V94.2) and Puertollano (V94.3).

Availability concepts

Availability Standards

When the availability or reliability of a plant is being described, such terms are often used in a very imprecise manner. Furthermore even if the reporter takes care to be accurate in his choice of words, the fact is that there are a number of different standards for reporting such data and there are (at least minor) differences between them.

The principal standards in use in the power industry are IEEE 762 "Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity" and ISO 3977-9:1999 "Gas turbines -- Procurement -- Part 9: Reliability, availability, maintainability and safety". Reporting in the gasification industry generally follows the "Guidelines for Reporting Operating Statistics" issued by the Gasification Technologies Council (GTC). All the standards define availability on a time basis. The GTC guidelines do provide for some reporting on a load or production basis.

The GTC guidelines divide the time in a year into four classes, as follows:

- Product not required
- Planned outages

[1] All gasification processes are described here by their current name, irrespective of the name current at the time of plant construction, thus Sasol-Lurgi for Lurgi, GEE for Texaco and E-Gas for Dow or Destec.

- Unplanned outages
- On stream

The GTC guidelines then provide formulas to derive "Forced outage rate" and "Availability" numbers. The GTC Guidelines are attached as an appendix to this report as are the IEEE 762 formulae.

What are the principal differences between these standards and where is the greatest potential for misunderstandings?

1. Firstly there is a difference between the standards in the handling of the time "Product not required". While IEEE 762 assumes that during this time the plant is 100% available, the GTC guidelines assume that the "Forced outage rate" is the same as for the rest of the year. This assumption, which is probably more realistic, produces slightly lower reported availability numbers than IEEE 762. For most chemical operations this difference is relatively unimportant because generally in such plants the "Product not required" time is extremely small. For power production, where the dispatch rate is dependant on a demand which is subject to both daily and seasonal fluctuations, this may be more important.
2. The two standards differ in their characterization of forced part-load operation. The GTC guidelines provide for using the total annual production in determining the "Annual loading factor". This statistic; however, does not distinguish between a part load operation caused by a lack of demand and one caused by technical limitations of the plant. Furthermore operation at a higher load than the nameplate capacity can partly mask part load operation and/or outage time. IEEE 762 explicitly counts forced part-load operation in the calculation of "equivalent planned and unplanned derated hours".
3. A third trap when reviewing availability statistics is the term "Planned outage". The GTC definition of planned outage is an outage which is known and planned for with at least one month's notice. From the point of view of production planning and dispatch this definition is perfectly legitimate. It does however also include outage which is required to remedy technical problems in the plant, but which because of, say, equipment lead-times is known about more than a month in advance. In contrast to annual shutdowns required for example for combustor inspection on gas turbines or, at longer intervals for statutory inspections these "planned" inspections are not included in the financial planning of a new project.

Methodology

The reporting of availability data for gasification plants in the public domain literature is not consistent – although in recent years the tendency has been increasingly to use the GTC definitions.

The attempt is made in this report to bring all the available data to a single, consistent and transparent basis – to the extent that the available data allows. In order to achieve this, all reported outage – irrespective of how it was originally reported in the literature – is calculated back to hours of outage. In some cases this is easy, in others it is necessary to make reasonable assumptions to arrive at a figure for hours of lost production. These hours are then expressed as a percentage of an 8760 hour year. For the reasons outlined above there is no attempt at this point to distinguish between planned and unplanned outage. Thus the figures are all comparable, irrespective of how this issue was handled in a particular source.

Caution

Nonetheless it is necessary to be cautious in the use of these numbers. The lower the reported availability of an individual plant, the more opportunity there is to perform additional work in parallel to repairing the immediate cause of outage. On the other hand when plants are reporting over 90% availability, the opportunity for such “masking” is reduced close to the point where it is no longer a possible source of significant error.

Another point of caution is of course the size of the available sample. The total number of syngas-fired gas turbines in operation on a worldwide basis is fourteen and not all these could be included in this report. By any measure of statistical evaluation this is not a large enough sample to justify any statistical conclusions. On the other hand there are parts of the plant that are built in sufficient numbers (e.g. air separation units, natural gas-fired gas turbines) that one can draw on validated statistical evidence from a wider installed base.

The aim of this report is therefore to consolidate and rationalize the available information in a form that will allow weak points to be analyzed and to develop reasonable projections for the availability of IGCCs on the assumption that the lessons learned are applied. What this report cannot do in more than a limited manner, is provide a strategy for ensuring that these lessons really are learned and implemented.

2
BASIC STRUCTURE OF THE IGCC

It is assumed at this point that the reader is familiar with the basic structure and concepts of the IGCC, which are shown in Figure 2-1. Within this framework however there is considerable scope for variation. The purpose of this chapter is to review the choices available within this basic structure, so that this can be related to the discussions on availability which follow in the main body of the report. Note that in this connection the main systems in the IGCC have been grouped into four major blocks, which are used for structuring the information in the report.

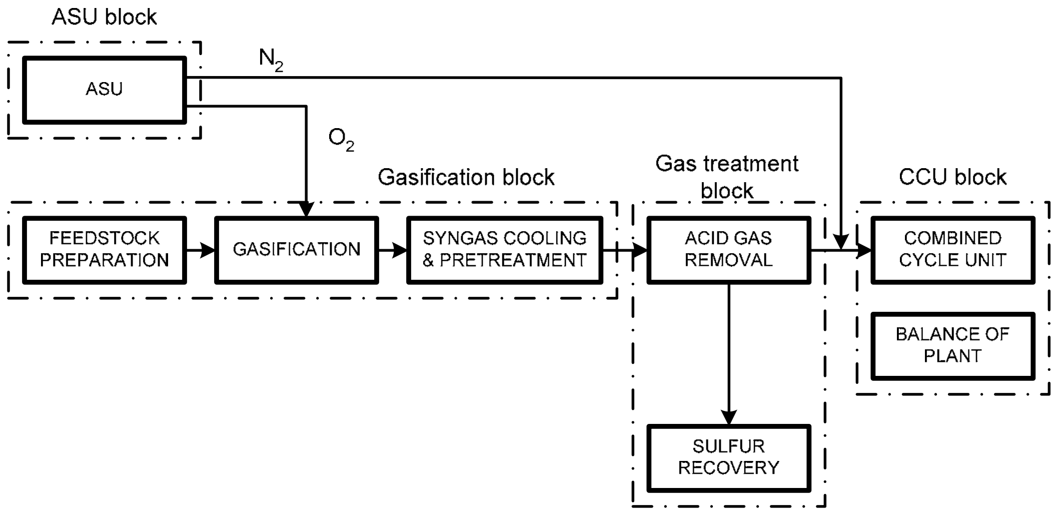

Figure 2-1
Basic Structure of an IGCC

Variations in State of the Art IGCC Configurations

Air Separation Block

The first variation to be considered is the extent of air-side integration, which can range from 0% as in Polk or Wabash to 100% as in Buggenum or Puertollano, where the degree of integration is defined as the percentage of air supplied to the ASU by extraction from the gas turbine. This difference in the first (1990s) generation of IGCCs can largely be attributed to the gas turbines available at the time. The 100% integration is clearly disadvantageous in today's economic environment, since a long start-up period using an expensive back-up fuel is required. On the other hand zero air extraction from the gas turbine air compressor does not allow optimum use of the machine over a full range of ambient conditions. The optimum degree of integration is dependant on many factors, including the ambient temperature range and the turbine selection. A typical figure today might be around 30%.

The quality of the oxygen is another variable. Over the range 85% (Puertollano) to 95% (most other plants) the optimum curve for energy consumption is fairly flat. Additional energy is required in the ASU to raise the quality further. A purity of 99.5% O_2 is typically not attractive for a straight IGCC application, but for chemical applications it is generally the standard. Where polygeneration is to be considered, one would need to review the oxygen purity specification on an individual case. If the co-product were to be ammonia for instance 95% O_2 would be perfectly satisfactory.

Other choices to be made include the distillation pressure in the ASU (making use of the higher pressure available from the extraction air) and the choice of oxygen compression system (gas phase or liquid phase). These choices are best left to the ASU vendor.

Finally a decision needs to be made on the provision of storage for liquid oxygen and liquid nitrogen. Both storage facilities are interconnected with the plant availability and are discussed in detail in Section 5 (page 5-4). Essentially oxygen storage can provide an opportunity for improving availability. Conversely, the poorer the availability, the more liquid nitrogen storage is desirable.

Air blown gasification, i.e. without any ASU at all is not considered in this report, although it should be noted that one such plant (Southern Company, Orlando) using the KBR Transport Gasifier is currently in the engineering stage.

Gasification

Variations in the gasification block are almost entirely dependant on the choice of technology supplier. Important differences are:

- In **Feedstock Preparation**, the use of rod mills for slurry preparation (GEE and ConocoPhillips) or roller mills and drying (Shell, Siemens). In both cases the particle size is of the order of magnitude of 100 microns. In the case of fluid bed processes such as the Transport Gasifier mentioned above, the particle size is much larger (~6mm).
- The **Feedstock Pressurization** is a directly connected to the feedstock preparation method. Slurry feed units use slurry pumps. Dry feed units need to employ lock hoppers and pneumatic conveying.
- For the **Gasifier** itself generally entrained flow gasifiers are considered in this report, the only exception being the moving bed gasifiers of the Dakota Gasification plant at Beulah, ND. The flow direction can be down flow (GEE or Siemens) or up flow (ConocoPhillips or Shell). The temperature containment can be with refractory (GEE or ConocoPhillips) or using a membrane wall (Shell or Siemens). Only ConocoPhillips uses a two stage gasifier. The other technology suppliers use single stage gasification.
- **Syngas cooling** is available in a number of variations:
  - Water quench (GEE or Siemens) is not currently used in the coal-based IGCC configuration, primarily because of an associated efficiency penalty. It is used however in chemical applications, particularly where CO shift for hydrogen manufacture is involved (Kingsport, Coffeyville). It is also used in a number of refinery-based IGCC units. Should CO_2 capture have to be implemented from the beginning of a project (as opposed to being retrofitted later), then this cooling technique would probably be favored also for coal-based IGCC applications.
  - Radiant cooling is only offered by GEE (e.g. Polk)

  - Fire tube convection cooling has been used by GEE (as second cooling stage in Polk) and by ConocoPhillips.
  - Shell uses a gas quench and water tube syngas cooling
- A certain amount of **Syngas Pre-treatment** is generally included in the scope of the gasification technology supplier. This includes removal of particulate matter and a number of trace components in the gas, particularly ammonia and chlorides. Shell and ConocoPhillips remove the particulates and the water soluble gases in separate stages, using a candle filter (sinter metal for ConocoPhillips and ceramic for Shell) for particulate removal and a water wash for ammonia and chlorides. GEE and Siemens combine these steps in a single scrubber.

Slag Removal from the pressurized gasifier is achieved using a lock hopper arrangement in most processes. Only ConocoPhillips has a proprietary continuous let-down system.

Gas Treatment and Sulfur Recovery

Although sulfur species (primarily H_2S) are the principal targets of the gas treatment system, it is necessary to consider the full range of potential contaminants, which include COS (a minor sulfur species) and mercury. Depending on the selection of desulfurization technology, COS will probably require to be hydrolyzed to H_2S to achieve the required level of sulfur removal. Typical temperatures for COS hydrolysis are between 160 and 200 °C (320 and 390 °F).

Mercury removal is best performed at ambient temperatures upstream of the acid gas removal so that some of the gas treatment will need to be integrated with the low temperature gas cooling. Mercury removal from syngas has only been practiced industrially at Kingsport although it is a regular feature of natural gas pretreatment in LNG plants.

There is an extremely wide variety of **Acid Gas Removal** (AGR) systems on the market. These can be classified as chemical washes (which include all amines such as MDEA or ADIP) and physical washes such as Selexol or Rectisol. In addition it is possible to have a mixed characteristic solvent such as Sulfinol. All of these named processes have been used in IGCC or chemical plant gasification operations. Selection is based on requirements for high purity (Rectisol) versus low cost (MDEA) with Selexol and Sulfinol lying in between on both counts. All these processes have a long track record in industrial practice, all with high availability records.

The chemical washes are generally not capable of absorbing COS, which must be converted to H_2S in a **COS hydrolysis** step upstream of the wash. Physical washes can absorb COS. In the case of Selexol this capability is not very strong and economics usually dictate the use of a COS hydrolysis as well (but not after a CO shift as in Coffeyville). Rectisol does not require any upstream COS hydrolysis.

Sulfur recovery is generally achieved using Claus technology, although Polk is an exception in that it manufactures sulfuric acid rather than elemental sulfur. Differences in the Claus technology itself are generally only of a detailed nature. Considerable variety is shown in the handling of the tail gas from the Claus plant, which in addition to H_2S also contains small quantities of SO_2, COS, CS_2 and elemental sulfur. In all plants these are hydrogenated back to H_2S over a catalyst. In some plants, this gas is then treated separately in another washing stage and then incinerated and discharged to the atmosphere. In others it is recycled to a point upstream of the main AGR so that this remaining gas is treated there. The point at which the recycle is fed into the main gas stream varies.

In all plants **Syngas Dilution** is used to reduce the NO_x emissions from the gas turbine. The dilution medium may be nitrogen only (Polk initially), steam only (e.g. Wabash) or a combination of the two (e.g. Buggenum and later also Polk). Steam is generally added by saturation using low level heat to provide the necessary hot water. In some cases it is added by direct injection (Pernis).

Combined Cycle Power Plant

The Combined Cycle Unit (CCU) block as described in Figure 2-1 covers the typical scope of a NGCC complete with balance of plant. The principal difference lies in the use of syngas as a fuel. Note that to date little experience is available on the use of selective catalytic NO_x reduction (SCR) in IGCCs, where the residual sulfur content in the syngas could impact on the availability of the HRSG. Two units in Italy are equipped with SCRs, but the required NO_x emissions levels are not comparable with the values required of a NGCC plant. In one case the SCR is only used when the gas turbine operates on the back-up distillate fuel. The only significant experience with SCR in IGCC is at the Negishi plant of Nippon Oil. Values of <2.6 ppm NO_x and < 2.0 ppm SO_x have been reported [Yamaguchi, 2004].

It should be noted that the "Balance of Plant" in an IGCC will include a flare and a process waste water system. While there are some lessons learned, both in terms of design and operating practice in these latter areas, particularly the flare, there is so little outage time attributable to the flare or the waste water treatment that they are not further discussed in this report.

Industrial Gasification in the Chemical Industry

Most of the issues concerning availability in IGCCs apply equally to chemical plants. The principal differences relate to the degree of desulfurization and the end use of the gas.

Typically most chemical processes require a very high degree of desulfurization (generally < 0.1 ppmv sulfur in the syngas, but < 20 ppbv in Beulah) to protect the downstream catalyst. For this reason most such plants use Rectisol for acid gas removal. (Coffeyville uses Selexol inherited from the Cool Water IGCC.) This system also removes COS, so that a COS hydrolysis step is not required. There is no fundamental reason why there should be a measurable difference in availability of the gas production and treating facility in a chemical plant from those used in IGCCs.

Most syngas-based chemical synthesis processes (e.g. ammonia, methanol, hydrogen, SNG) have little in the way of rotating machinery except a syngas booster/recirculation compressor. Intervals between catalyst replacements may be 3 years or even longer. Thus chemical synthesis units tend to have an availability which is inherently higher than that of a gas turbine, which requires annual combustor inspections and once-every-three-years hot gas path inspections. It is important to bear this in mind when comparing the performance of power plant with chemical plant.

3
SELECTED IGCC PROJECTS

Nuon Power, Buggenum, The Netherlands

Plant description

Nuon Power's 253 MW_e (net) IGCC power plant in Buggenum, The Netherlands, was taken into service as a demonstration facility in 1994. The plant was built by Demkolec, a consortium of Dutch power producers next to an existing coal fired power station on the River Maas. Thus the existing coal reception and handling facilities could be used for the new demonstration unit.

After completion of the demonstration period and with the liberalization of the Dutch energy market, the plant was acquired by Nuon. The plant was then operated in a peak-shaving mode for a period of a year or more (2003 - 2004). In the meantime it has returned to base-load operation.

The principal characteristics of the plant design are as follows:

- **Air Separation Unit**: The ASU is 100% air-side integrated with the gas turbine. The oxygen purity is 95%. Pure nitrogen is generated for use as carrier gas for the dry-feed gasifier and for purging purposes. The total balance of nitrogen from the ASU is compressed for use as dilution nitrogen (DGAN, <2% O_2) in the gas turbine.

Oxygen and DGAN are compressed in turbo-compressors. In addition there is a high pressure nitrogen compressor for the pure nitrogen.

Oxygen storage is provided both as liquid oxygen (LOX) and gaseous oxygen (GOX). The GOX storage is at high pressure (bullets) and has sufficient capacity to stabilize the high pressure system until the LOX back up kicks in. The LOX back up storage is equivalent to several hours operation.

- **Coal gasification**: The gasifier is a single dry-feed Shell SCGP unit without spare.

The plant was designed for a wide range of imported, internationally traded coals. In the meantime the plant operates with a substantial component of biomass (up to 30%-mass tested) in response to the Dutch renewables incentives.

The **fuel preparation** takes place in 3 x 55% roller mills in which the coal is ground to a particle size of < 100μ. The pulverized fuel is partly dried in the mills. Final drying is effected by burning a small stream of syngas as fuel. The fuel is brought to plant pressure by means of lock hoppers (two trains) and is conveyed pneumatically to the four side-mounted burners with high purity nitrogen as carrier gas.

The **gasifier** itself operates at 25 barg (360 psig) and a temperature of about 1600°C (2900°F). The carbon conversion rate is over 99%. The gasifier has a steam-generating membrane wall as temperature containment.

The slag produced in the gasifier leaves the gasifier at the bottom via a quench bath and lock hoppers. There is no slag crusher in the outlet.

At the outlet of the gasifier the raw syngas is quenched to a temperature of about 900°C (1650°F) with recycled, cooled, particle-free syngas. The synthesis gas is then cooled to about 235°C (455°F) in a water-tube boiler generating high pressure and intermediate pressure steam.

Particulate matter (mostly fly ash with a very small amount of unconverted carbon) is removed from the syngas first via a cyclone and then with a ceramic candle filter.

The gasification section is completed by scrubbing the gas with water at about 165 °C (330 °F) to remove ammonia and halides.

- The **Acid Gas Removal** consists of a HCN/COS Hydrolysis and a Sulfinol M Wash which reduces the total sulfur content of the syngas to <20 ppmv S. The sour gas is processed in a single Claus unit to elemental sulfur. The tail gas is not recycled but hydrogenated and treated in a SCOT unit before discharging the cleaned tail gas to the atmosphere via an incinerator.
- The **Combined Cycle Unit** is based on a Siemens V 94.2 gas turbine. The gas and steam turbines are mounted on a single train and drive a common 285 MW generator. For NO_x reduction the synthesis gas is mixed with nitrogen. The mixture is then saturated with water vapor.

The HRSG generates steam at 120 bar g/540 °C, 22 bar g/540 °C (reheat) and 4.6 bar g (1740 psig/1000 °F, 320 psig/1000 °F, 70 psig).

The electrical energy balance is as follows:

Production	MW_e	Consumers	MW_e
CCU	285,0	ASU	
		Gas production	
		CCU	
Sum	**285,0**	**Sum**	**32.5**

Net power production: 252,5 MWe.

- The **waste water** concept is that of zero process water discharge. Water from the syngas scrubber is stripped and recycled. Excess water is treated and finally evaporated to leave the salts as a solid waste or by-product.

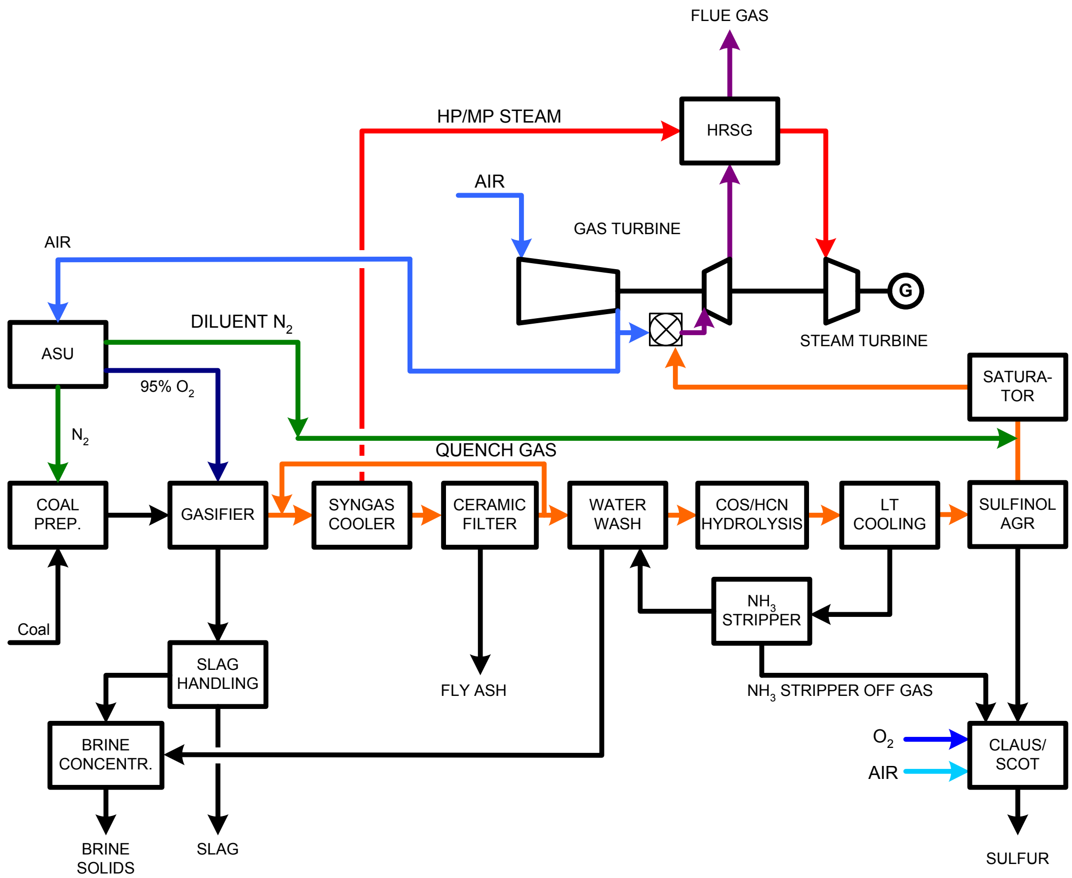

Figure 3-1
Block Flow Diagram, Buggenum IGCC

Operating history

The annual availabilities achieved in Buggenum with syngas and natural gas are shown in Figure 3-2.

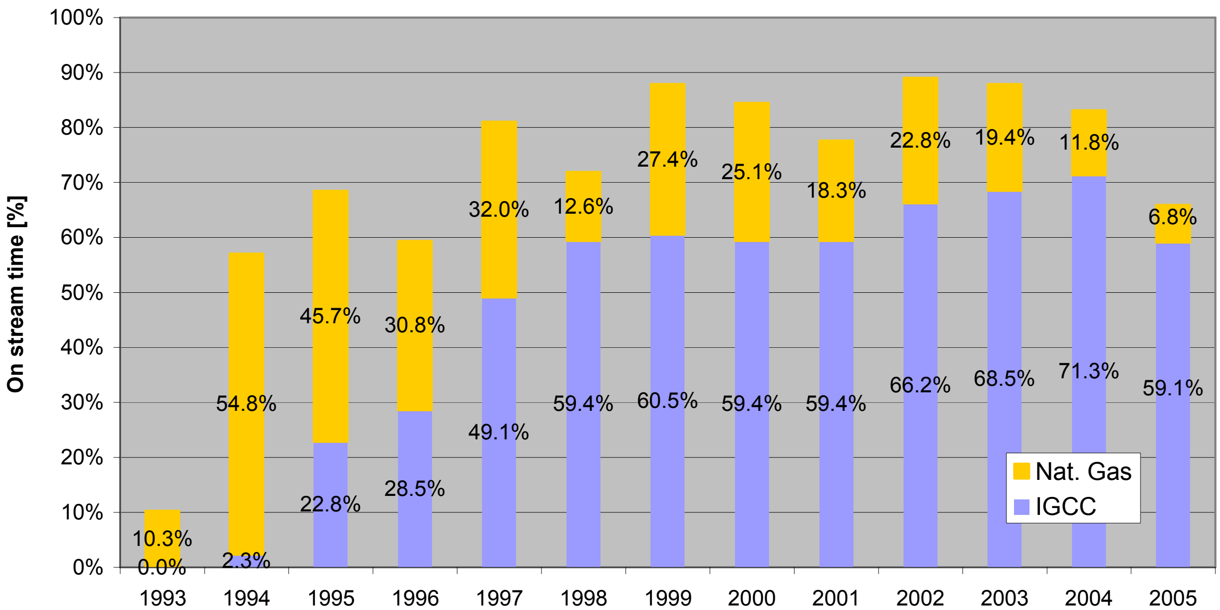

Figure 3-2
Annual on stream time in Buggenum[2]

The demonstration period was completed at the end of 1997 and since 1998 the plant has been operated as a commercial unit. In 2002 as a result of the restructuring and liberalization of the Dutch power industry, it began operating as a peak shaving unit. In IGCC mode a ramp speed of 1.5 MW/minute could be achieved. This could be increased to 3.5 MW/minute by adding natural gas. During this period the demand from the unit was changing every four seconds [Kanaar, 2002].

Another important and very beneficial change was made at this time. Until 2002 the plant had had no influence on the coal procurement strategy. A large number of plant trips until this time could be attributed to uncontrolled changes in the quality of the coal, which it received from the neighboring PC units. From 2002 the IGCC plant became responsible for its own coal procurement and this source of plant trip ceased [Kanaar, 2002].

In 2004 the plant returned to base load operation.

A further important change to the plant was made at this time. The existing DGAN compressor was modified so that it could serve as a start-up air compressor for the ASU. This removed one of the important disadvantages of the 100% air-side integration, namely that the gas turbine was required to operate on natural gas for three days to bring the ASU from ambient to operating temperatures before the gasifier could be brought on line. [Hannemann et al, 2002]

Run lengths of over 2500 hours of uninterrupted IGCC operation have been achieved.

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[2] Note that the data for 2005 include about seven weeks during which test on the “syngas-start capable” combustion turbine fuel nozzles were conducted. Allowance for this would increase the IGCC availability to about 72%, similar to 2004.

In 2005 the plant implemented two projects aimed at improving the economics for the specific location; increased biomass feed so as to take advantage of credits for "green power" and a capability to start the gas turbine on syngas so as to eliminate a high connection fee for natural gas. The former required modifications to the feed system to accommodate increased biomass feed on a regular basis and the latter required a modification to the gas turbine burners. The new burners were installed in the summer and testing continued into the fall (see data in Appendix B), which explains the lower on-stream time recorded in 2005.

A number of important issues arose and were resolved during the demonstration period, including the following:

- GT Vibrations;
- Syngas Scrubber corrosion;
- Sulfinol degradation;
- Ceramic candles;
- Slag lumps and fines discharge.

Some issues revealed themselves later, but have also been rectified:

- Erosion and corrosion in the slag bath system:
- ASU valves.

Other issues are still on-going, in particular:

- Syngas Cooler leakages

These and other issues are discussed under the appropriate headings in Chapter 5.

Wabash River Energy, Terre Haute

Plant Description

The 250 MW_e (net) "Wabash River" Project went on stream in October 1995 as the first of the DOE supported IGCC power plants. The project was developed jointly by Destec, at the time the owner of the gasification technology, which is today owned by ConocoPhillips and marketed as E-Gas and which had originally been developed by Dow Chemical, and PSI, owner of the existing conventional coal-fired Wabash River power station in Indiana and a subsidiary of Cinergy Corp. (now Duke Energy), which is now planning a new IGCC power plant at Edwardsport, Indiana. The ownership of the gas production (including the air separation unit and gas treatment) remained with Destec, which had a contract to supply the treated syngas to PSI. PSI built a new gas turbine and used one of the existing steam turbines from the old power station for the steam cycle.

The gas production unit is now owned by SG Solutions LLC, a 50/50 joint venture of Global Energy Inc. and Wabash Valley Power Association. The ownership of the combined cycle section was recently (December 2006) transferred to Wabash Valley Power Association.

The former split ownership of this facility makes it difficult to assemble numbers in comparable detail to that of some of the other plants.

The principal characteristics of the plant design are as follows:

- **Air Separation Unit**: The ASU is not integrated with the CCU, either on the air side nor on the nitrogen side. The oxygen has a purity of 95%. A small pure nitrogen stream for purging the plant is generated. The remaining nitrogen is vented back to the atmosphere.

  Oxygen is raised to the gasifier pressure by a turbo compressor.

  There is no oxygen storage, neither as liquid (LOX) nor as gas (GOX). A liquid nitrogen storage tank is included in the plant.

- **Coal gasification**: The gasifier is a two-stage, slurry feed E-Gas unit. A spare reactor is available off-line (a "hot switch" between gasifiers is not feasible).

  The plant was originally designed for coal feed, but petroleum coke was successfully used as feed (up to 100%) already during the early operation. Much of the subsequent operation has been on 100% pet coke because of the favorable economics.

  The **Slurry preparation** takes place in a single rod mill. The slurry is stored in an agitated tank each with a capacity sufficient to meet maintenance requirements on the rod mill and feeder. Two membrane pumps raise the slurry pressure to the gasifier inlet pressure.

  The **gasifier** itself operates at 27.6 bar g (400 psig) and a temperature of about 1425°C (2600°F) in the first stage and 1040°C (1900°F) at the outlet of the second stage. Both stages of the gasifier are refractory lined.

  The **syngas cooling** takes place in a fire-tube convection cooler.

  The **gas pretreatment** is carried out in two stages. Particulate matter is first removed in a candle filter (initially ceramic, later changed to sinter metal). Subsequently ammonia and chlorides are removed by water in a scrubber (retrofitted at a very early stage in the project). The scrubber outlet temperature is about 165 °C (330 °F).

  The slag leaves the bottom of the reactor via a slag crusher and a special let-down arrangement with no valves (i.e. not a lock hopper).

- The **Acid Gas Removal** consists of a COS hydrolysis and an MDEA wash. The sour gas is processed to liquid, elemental sulfur in an oxygen-blown Claus unit. The Claus tail gas is hydrolyzed and recycled back to the gasification reactor.

- The **Combined Cycle Unit** is based on a GE 7FA gas turbine. NO_x reduction is achieved by saturating the syngas with water vapor without the addition of nitrogen. The saturation takes place in a saturator column which utilizes the low level heat in the plant.

  The three level HRSG generates HP steam and superheats the steam from the process unit at 110 bar g (1600 psig).

  The steam turbine is a 1953 Westinghouse machine with a rating of 110 MW_e.

The electrical energy balance is as follows:

Production	**MW_e**	**Consumers**	**MW_e**
Gas turbine	192,0	ASU	
Steam turbine	96,0	Gas production	
		CCU	
Sum	**288,0**	**Sum**	**36,0**

Net power production: 252,0 MW_e.

- The **waste water** concept includes a sour water stripper. The waste water system was upgraded with a mechanical vapor recompression system in 2002, primarily to reduce trace amounts of arsenic and selenium in the process blowdown [Keeler, 2002].

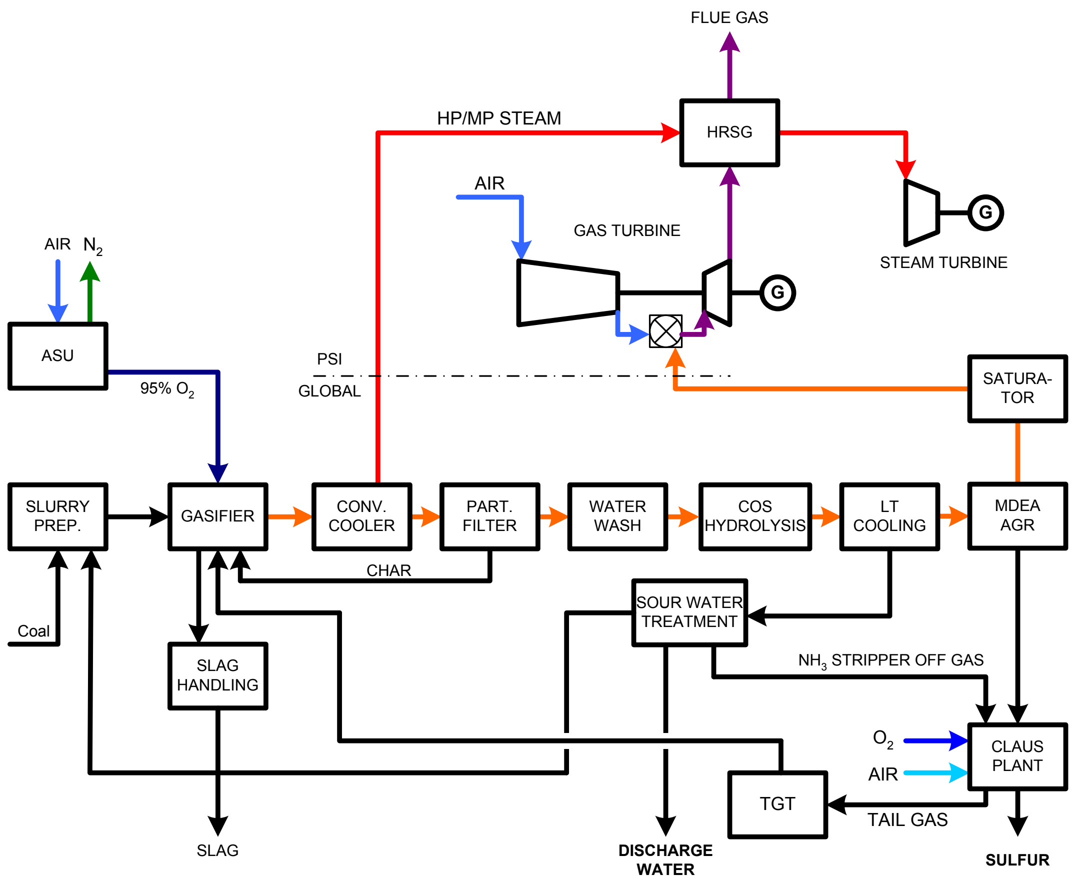

Figure 3-3
Block Flow Diagram, Wabash River IGCC

Operating history

The annual availabilities achieved at Wabash are shown in Figure 3-4.

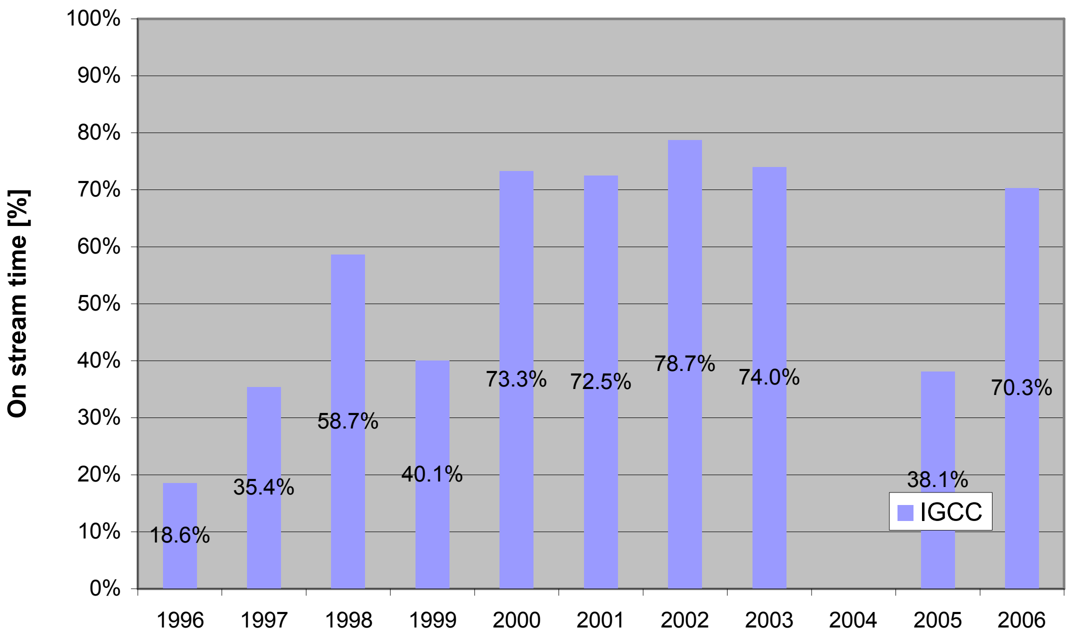

Figure 3-4
Annual on stream time at Wabash[3]

The plant was shut down over a business dispute from February 2004 to June 2005. Following the formation of SG Solutions the plant was returned to service in June 2005 and operated for 3335 hours in 2005. The plant has more recently shown improved Gasifier and Power Block operation with more stable continuous operating periods. In the period from November 2005 (end of the Fall 2005 outage) to September 2006, the power block and ASU accounted for over half of the forced outage hours and a manufacturing defect in the slurry tank agitator shaft was responsible for 15% of the downtime.

During the first eight months of 2006, Wabash Valley Power Authority reported 4220 hours of IGCC operation (circa 72%), but the facility took a 10-week planned outage in the fourth quarter of 2006 to address several deferred maintenance issues which had been impacting availability for a number of years (most notably the design of the HRSG). The facility reported to the US EPA a total of 6160 hours (70.3%) of total operation in 2006 though it is not clear how many of those hours were on syngas.

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[3] These figures include a business dispute 2004-June 2005 and a 10 week planned outage in 2006. See text for details.

Tampa Electric Company, Polk Power Station

Plant description

The 250 MW_e (net) Polk Power Station in Florida was the second of the DOE supported IGCC power plants to go on stream (September 1996). The plant has been continuously under the ownership of Tampa Electric Company. The plant design concept was largely based on up-scaling the Cool Water 100 MW_e demonstration plant in California.

The principal characteristics of the plant design are as follows:

- **Air Separation Unit**: The original design of the ASU was without any air side integration. As a debottlenecking measure when operating with petroleum coke an air extraction has been built into the gas turbine in 2005. Oxygen purity is 95%. Waste nitrogen (DGAN, 1.5-2% O_2) from the ASU is used in the gas turbine for NO_x reduction. A smaller stream of pure nitrogen (50 ppm O_2) is used for purging purposes.

  The air compressor has a power demand of 34 MW, the oxygen compressor of 6.5 MW and the nitrogen (DGAN) compressor 14 MW. There is a second high pressure (57 bar g) nitrogen compressor for the purge nitrogen with a power demand of 1.1 MW.

  There is no oxygen storage, neither as liquid (LOX) nor as gas (GOX). The plant has two liquid nitrogen storage tanks each with a capacity of 75 m³ (2650 ft^3).

- **Coal gasification**: The gasifier is a single-stage, slurry feed GEE Radiant Cooler design with subsequent fire-tube boiler. There is no spare reactor.

  The plant was originally designed for operation on coal feed (Pittsburg #8 and others). In the meantime the feed has been switched to a 55/45% pet coke/coal mixture because of the improved economics. The specific oxygen demand for pet coke is higher than for coal and a limitation on the throughput of the ASU air compressor has limited raising the pet coke proportion of the feed any further.

  The **Slurry preparation** takes place in 2 x 55% rod mills. The slurry is stored in two tanks, each with a capacity equivalent to 4 hours operation. A single Geho membrane pump (without spare) is used to raise the pressure of the slurry to about 35 barg (500 psig) for charging the gasifier.

  The **gasifier** itself operates at 28.9 barg (420 psig) and a temperature of between 1300 and 1500 °C (2400 – 2800 °F). The gasifier was designed for a carbon conversion of 97.5-98%. In fact it reached substantially lower values (90-95% according to the DOE Final Report). The syngas generated in the gasifier is cooled to about 750 °C (1380 °F) in the radiant cooler mounted immediately below the gasifier. The radiant cooler generates high pressure saturated steam at 114 barg (1650 psig). The slag falls to a water bath in the bottom of the radiant cooler together with about 50% of the unconverted carbon. The remaining portion of the unconverted carbon, together with some fly ash, leaves the gasifier with the syngas.

  The Polk plant is unusual in having two syngas outlet nozzles and two parallel fire-tube convection coolers. These originate with the original intention to demonstrate a hot gas desulfurization process in a slip stream of the main plant. This demonstration unit was never taken into service, but this feature has remained. The syngas is cooled in the convection coolers down to about 380-400°C (700-750°F) also generating 114 barg (1650 psig) saturated steam.

A water scrubber then removes the particulate matter (char and fly ash) as well as ammonia and chlorides. The scrubber outlet temperature is about 165°C (330°F).

The slag leaves the water bath in the reactor sump via a slag crusher and lock hoppers.

- The **Acid Gas Removal** consists of a COS Hydrolysis (retrofitted at an early stage) and an MDEA wash. The sour gas is processed directly to sulfuric acid to supply the local phosphate fertilizer industry.
- The **Combined Cycle Unit** is based on a GE 7FA gas turbine. Originally just nitrogen addition was used for NO_x reduction. In 2001 a saturator was added in response to a requirement to reduce NO_x emissions from the original 25 to 15 ppmvd.

  The HRSG produces steam at 103 barg/540°C, 22 barg/540°C (reheat) and 3,5 barg (1500 psig/1000°F, 320 psig/1000°F, 50 psig).

  The electrical energy balance is as follows:

Production	**MW_e**	**Consumers**	**MW_e**
Gas turbine	192.0	ASU	56.3
Steam turbine	128.2	Gas production	5.7
		CCU	5.7
Sum	**320.2**	**Sum**	**67.7**

  Net power production: 252.5 MW_e

- The **waste water** concept is that of zero process water discharge. Water from the syngas scrubber is stripped and recycled. Excess water is treated and finally evaporated to leave the salts as a solid waste or by-product.

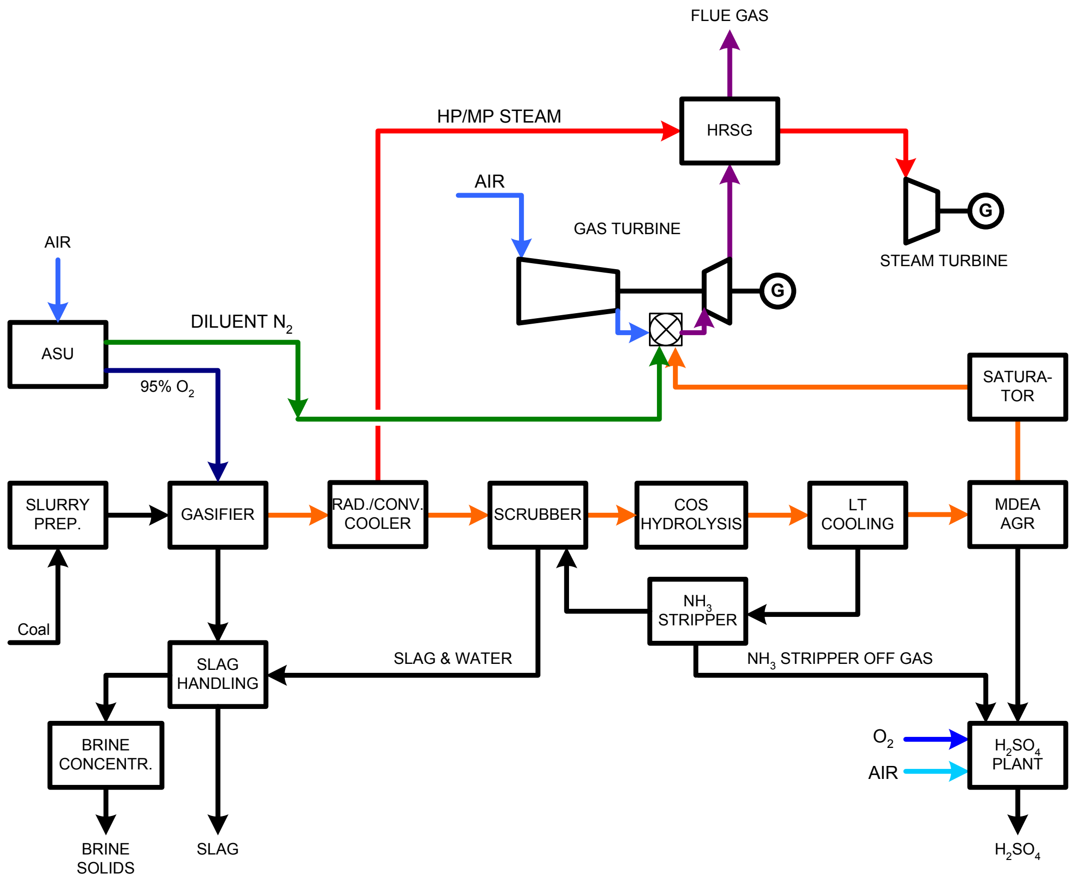

Figure 3-5
Block Flow Diagram, Polk IGCC

Operating history

The annual availabilities achieved at Polk are shown in Figure 3-6.

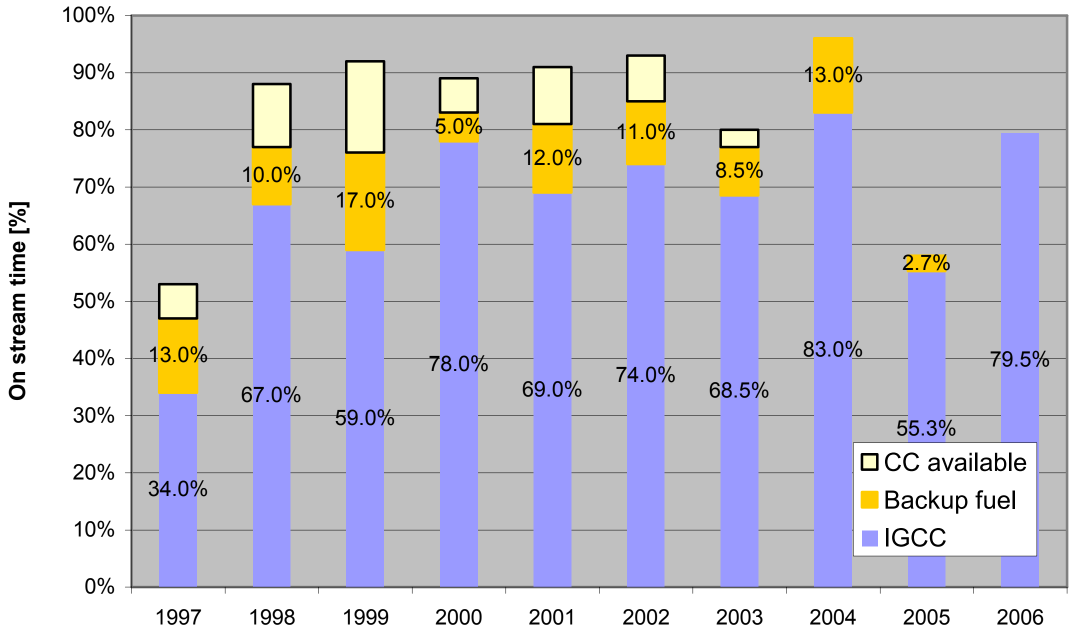

Figure 3-6
Annual on stream time at Polk[4]

In January 2005, there was a combustion turbine compressor failure that caused a 100-day outage. The cause was compressor discharge case creep. An additional 45-day outage was taken in April 2006 to replace the compressor discharge casing and address the creep issue. After returning to service from the turbine compressor failure in May 2005, the gasifier was on-line 90.6% of the time for the five month peak demand period May –September; 6.8% of the time was needed for cleaning of the convective syngas cooler, and 2.6% for other miscellaneous outages.

During the 45 day outage in April - May 2006, several additional improvements were made. The gasifier refractory was replaced after a record 3-year life. Additional surface was added to the radiant syngas cooler platens to reduce the outlet temperature in an attempt to reduce the fouling of the convective syngas coolers. A booster pump was added on the slurry feed line to accommodate the addition of a strainer in that line. Apart from the 45-day outage in 2006, the gasifier was on line 91.2% through September. The major downtime cause was the convective syngas cooler fouling (7%) and other (1.8%).

TECO has reported a total of 6960 hours of operation in 2006 to the US EPA, which represents a total on-stream factor of 79.5% (syngas plus natural gas operation).

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[4] 2005 includes 100 day outage for air compressor on gas turbine. Split between IGCC and backup fuel not available for 2006.

Elcogas, Puertollano

Plant description

The 300 MW_e (net) Puertollano IGCC power plant in Spain went into operation in December 1997. The gas turbine was first operated on synthesis gas in March 1998. The project was supported by the European Union's Thermie program. Seven European power producers as well as a number of key component suppliers joined together to form the operating company ELCOGAS.

The principal characteristics of the plant design are as follows:

- **Air Separation Unit:** The ASU is 100% air-side integrated with the gas turbine. The oxygen purity is 85%. Pure nitrogen (>99.9% N_2) is generated for use as carrier gas for the dry-feed gasifier and for purging purposes. The balance of nitrogen from the ASU is compressed for use as dilution nitrogen (DGAN, <2% O_2) in the gas turbine.

  The ASU is operated in a load following mode from the gasifier load.

  The oxygen compressor has a estimated nominal power demand of 7 MW and the DGAN nitrogen compressor of 24 MW. There is a second, high pressure (48 barg, 700 psig) nitrogen compressor supplying the carrier gas and a third compressor to supply LP purge nitrogen at 3 barg (45 psig)

  There is a liquid oxygen (LOX) tank with vaporizer. The liquid nitrogen (LIN) storage tank contains sufficient nitrogen for 3 plant starts.

- **Coal gasification**: The gasifier is a Krupp-Koppers (today Uhde) dry-feed Prenflo reactor. There is no spare reactor.

  The plant was designed for a feed consisting of a 50-50 mixture of local, high-ash (about 40wt%), low sulfur coal and petroleum coke from the neighboring Puertollano oil refinery.

  The **fuel preparation** takes place in 2 x 60% roller mills in which the coal is ground to a particle size of < 50-60μ. The pulverized fuel is partly dried in the mills. Final drying to a residual moisture of under 2wt% is effected partly with MP steam and partly by burning a small stream of natural gas as fuel. The fuel is brought to plant pressure by means of lock hoppers and is conveyed pneumatically to the four side-mounted burners with high purity nitrogen as carrier gas.

  The **gasifier** itself operates at 25 barg (363 psig) and a temperature between 1200 and 1600°C (2200-2900°F). The carbon conversion rate is over 98%.

  The slag produced in the gasifier contains less than 1% residual carbon. The slag leaves the gasifier via a slag crusher and lock hoppers.

  The raw syngas at the outlet of the gasification chamber is quenched with a flow of cooled, particle-free, recycled syngas to a temperature of about 900°C (1650°F) and subsequently cooled to about 236°C (450°F) in two water-tube syngas coolers, which generate saturated steam. The high pressure boiler is integrated into the gasifier, whereas the IP boiler is in a separate vessel.

  Particulate matter (mostly fly ash with a very small amount of unconverted carbon) is removed from the syngas with a ceramic candle filter. Part of the filtered gas is recycled as quench gas.

The gasification section is completed by scrubbing the gas with water at about 165°C (330°F) to remove ammonia and halides.[5]

- The **Acid gas removal** consists of a COS hydrolysis and an MDEA wash. The sour gas is processed to solid sulfur in a Claus unit. The tail gas from the Claus unit is hydrogenated and recycled to the COS hydrolysis.
- The **Combined cycle** unit is based on a Siemens V 94.3 gas turbine. The syngas is saturated and then diluted with syngas for NOx reduction.

  The HRSG produces steam at 122 barg/506°C, 35 barg/506°C (reheat) and 6,5 barg (1750 psig/940°F, 500 psig/940°F, 80 psig).

  The electrical energy balance is as follows:

Production	**MW_e**	**Consumers**	**MW_e**
Gas turbine	200,0	ASU	
Steam turbine	135,0	Gas production	
		CCU	
Sum	**335,0**	**Sum**	**35,0**

  Net power production: 300 MW_e

- The **waste water** is treated on site. The discharge from the sour water stripper is ozonized to reduce the HCN content to below 0.2 mg/l. The water is discharged to the Ojailén river. [Thermie Report, 2001]

[5] See discussion on COS hydrolysis for discussion of this temperature.

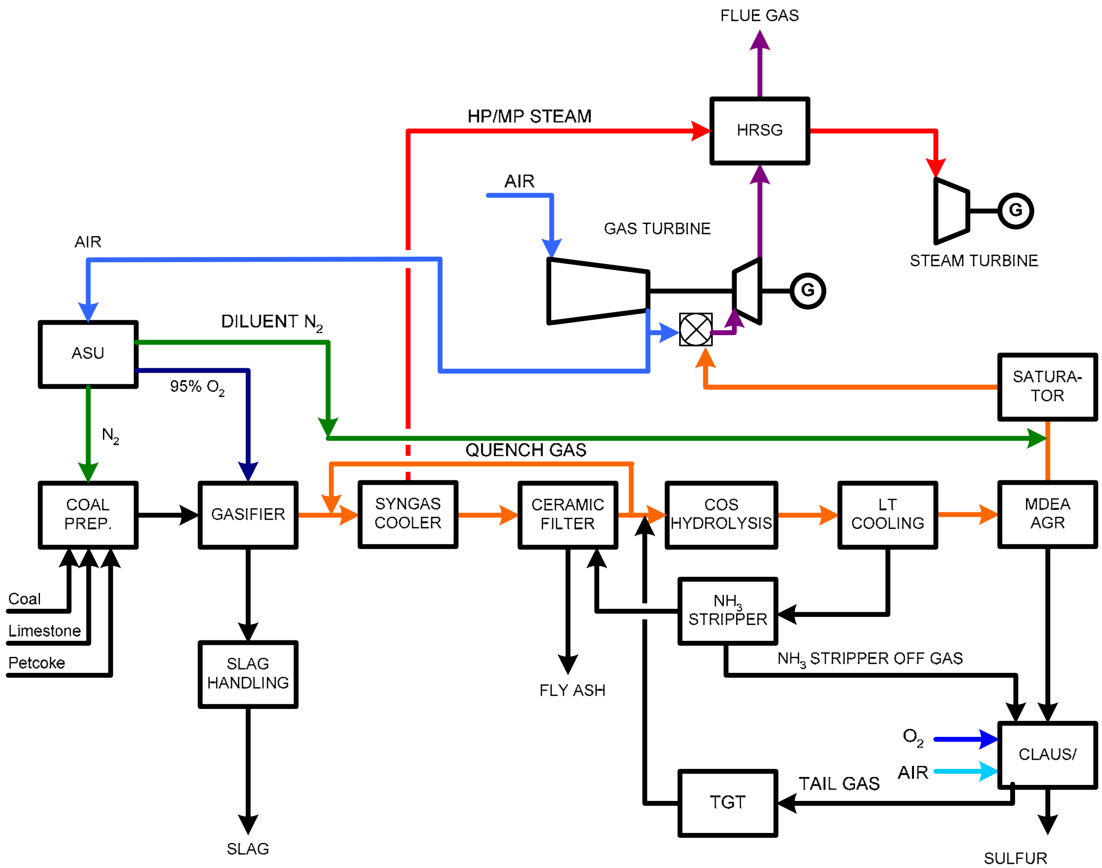

Figure 3-7
Block Flow Diagram, Puertollano IGCC

Operating history

The annual availabilities achieved in Puertollano are shown in Figure 3-8.

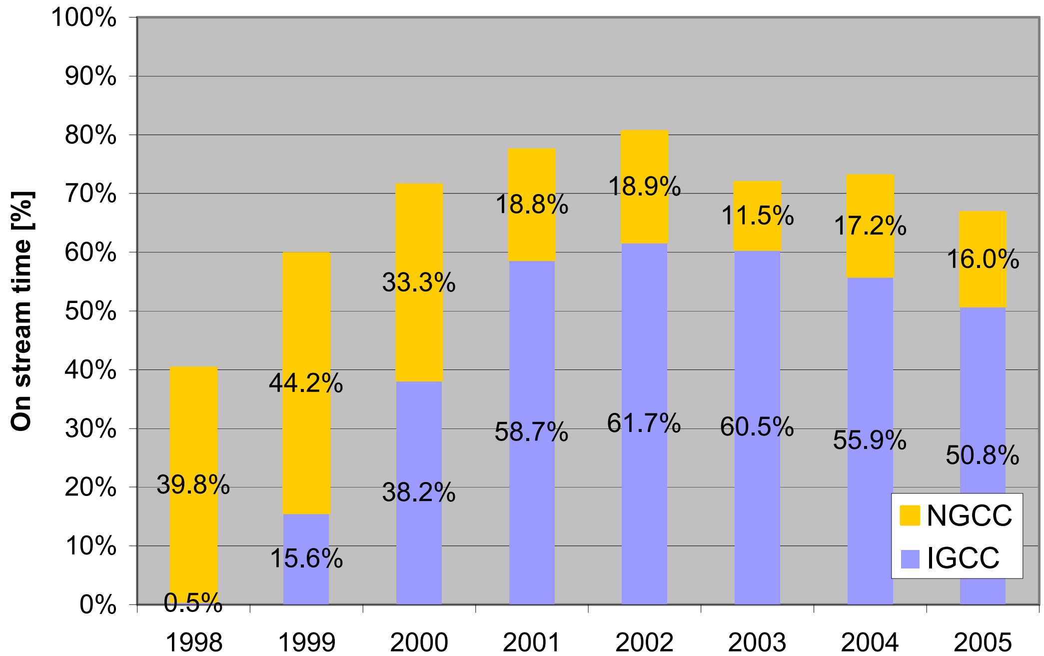

Figure 3-8
Annual on stream time in Puertollano

Elcogas has published a list of major issues limiting the plant availability [Garci Peña, 2005]:

1. Gas Turbine
   - Optimization of syngas burners to prevent overheating / humming and to accomplish more stability and remaining life of the hot components.
   - Up to last design of syngas burner was installed in 2003 preventive inspections of hot gas path every 500 – 1000 syngas operating hours. High rate of ceramic tiles change.
2. Gasifier
   - Water leakage of membrane tubes due to flow blockages or local erosion. Design of distributors. Chemical control. Particle filtration. Loose parts.
   - Gas leakage due to piping corrosion. Proper selection of materials. To avoid "cold ends" and down time corrosion.
   - Fouling of Waste Heat boilers:
     - Sticky fly ash (reduced by decreasing gas inlet temperature to cooling surfaces. More quench flow)
     - Fluffy fly ash (reduced by increasing the velocity of the gas)
3. Grinding and mixing systems
   - Clogging in mills feeding and mixing conveyors. Two trains of 60%. Lack of robustness of equipment.

4. Solids handling (slag and fly ash)
   - Erosion of components by local high velocities. Substitution of parts for abrasion resistant materials. Revision of design and operating procedures.
5. Ceramic filters
   - Life time of filtrating elements is half of expected (4000 h). Very expensive cost. To improve by changing supporting design of elements.
6. Fuel dust conveying and feeding systems
   - Pressure control and fluidization stability. Design of fluidization systems and preventive maintenance of components.
7. COS catalyst
   - 2 – 3 changes by year of alumina based catalyst. Water carryover. Change to Titanium oxide catalyst (3 – 4 years) and preheater installation.

[Note: The titanium catalyst was damaged by oxidation in August 2005. Then, in January 2006 it experienced a temperature excursion >250ºC during initial warm up. Elcogas replaced it at that time, and again at the end of April. They have decided to switch back to using alumina catalyst which is only $1/8^{th}$ the cost of the titanium catalyst.]

Valero, Delaware City

Plant description

The plant was built by Motiva Enterprises at the Delaware City Refinery to gasify the coke produced in the refinery. The plant was taken into service on 2000. The ownership of the refinery has changed twice since that time – initially being owned by Premcor and now Valero.

- **Air Separation Unit:** The ASU was supplied by Praxair. It has no air side integration with the CCU, but does provide dilution nitrogen for the gas turbines. The oxygen purity is 99% and the plant produces argon as a byproduct.
- **Coke Gasification:** 2100 t/d petroleum coke is gasified in two GEE quench reactors.

  The **slurry preparation** takes place in two 50% ball mills. The coke and fluxant material is received from modified existing coal silos. The slurry is stored in two slurry run tanks.

  The gasifier operates at 1000 psig (70 barg) and around 2500 °F (1371ºC).

  The syngas is cooled by full water quench with water scrubber.

  The slag from the lock hoppers is dumped onto a slag pad.
- The **Acid Gas Removal** is an MDEA wash. The acid gas is processes in a Claus sulfur recovery unit with SCOT tail gas treatment. There is no COS hydrolysis.
- The **Combined Cycle Unit** is based on two GE 6FA gas turbines. Nitrogen is used as diluent. Low sulfur diesel is used as a backup fuel.

  The HRSGs are fitted with supplemental duct firing. Steam is raised at 1250 psig (86 barg) and 175 psig (12 barg).

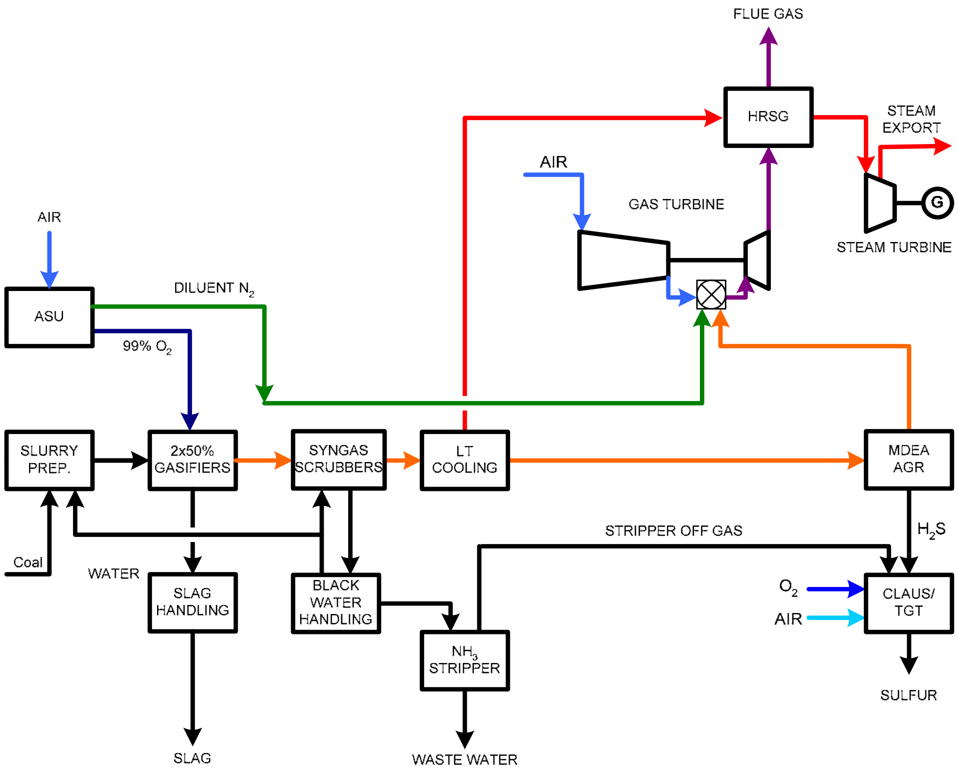

Figure 3-9
Block Flow Diagram, Delaware City

Operating history

The annual availabilities achieved in Delaware City are shown in Figure 3-10.

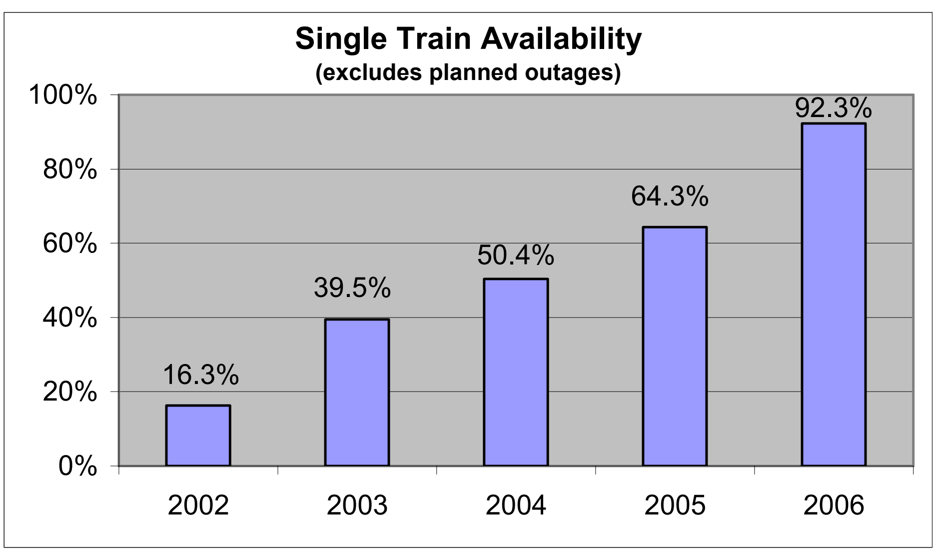

Figure 3-10
Annual Single Train Availability in Delaware City

Shell, Pernis

Plant description

The plant serves to gasify refinery residues in the Shell refinery in Rotterdam-Pernis manufacturing hydrogen for use in the refinery and simultaneously producing about 130 MW_e (gross) electric power. The power production corresponds to about one third of the total syngas production. The gasification plant uses 3 x 33 1/3% gasifiers. The gas turbine is built for syngas and natural gas operation. Typically if one gasifier is out of operation the hydrogen production is maintained at full load and the gas turbines switch over to natural gas.

The principal characteristics of the plant design are as follows:

- **Air Separation Unit:** The oxygen is manufactured in an ASU owned and operated by Air Products at their site in Rozenberg, about 7 km from the gasification site. There is no air or nitrogen integration for the gas turbine. A small quantity of high purity nitrogen is supplied, principally for purging.

  The oxygen purity is 99.5% O_2. This high purity was selected to maintain the inert gas component in the product hydrogen as low as possible. (This is a particular feature of the process selected for hydrogen final purification, methanation, which does not remove nitrogen from the syngas. The alternative, pressure swing adsorption, would remove any nitrogen from the raw hydrogen as part of the final purification step.)

  The ASU site has liquid backup storage. The length of the pipeline from Rozenberg to Pernis provides a substantial GOX buffer.

- **Oil gasification**: The gasification plant consists of three 33 1/3% Shell SGP oil gasifiers. There is no spare gasifier. Note that the Shell oil gasifiers are completely different from their coal gasifiers. The oil gasifier is a top fired, refractory-lined vessel with gas outlet at the side just above the bottom of the vessel.

  The feedstock comes directly from the upstream thermal cracker without any intermediate storage.

  The **gasifiers** themselves operate at about 60 barg (870 psig) and a temperature of about 1300°C (2375°F). The carbon conversion is about 99,5%. The unconverted carbon, together with the vanadium-rich ash is washed out of the raw syngas with water.

  The syngas cooling takes place in a fire-tube boiler close-coupled to the gasifier. The pressure of the saturated steam is 94 barg (1360 psig).

  The soot water from the water wash is filtered and the filter cake is combusted at low temperature in a multiple hearth furnace to recover a vanadium concentrate.

- The **Acid gas removal** consists of a two-stage Rectisol wash with a CO shift (for the hydrogen production) unit between the H_2S/COS stage and the CO_2 stage. The Rectisol unit achieves the desulfurization necessary for the hydrogen production (< 0.1 ppm S) without the necessity of including a COS hydrolysis. The syngas supplied to the gas turbine is only washed to a sulfur purity of about 20 ppmv (estimated, exact number not published).

  The sour gas is processed to elemental sulfur in the central Claus units of the refinery. The tail gas is treated in a SCOT unit where the tail gas is hydrogenated and washed before being released to the atmosphere via an incinerator.

- The **Combined Cycle Unit** is based on two GE MS 6541 B gas turbines with two HRSGs and two steam turbines. Since nitrogen is not available in large quantities, NO_x reduction is effected by steam injection. A CO_2 rich stream with low heating value from the Rectisol unit is also used.

  The three level HRSG produces HP steam at about 90 bar g/535 °C (1300 psig/1000 °F). The HRSG is equipped with supplementary firing to maintain the required superheat.

  The electrical energy balance is as follows:

Production	MW_e	Consumers	MW_e
Gas turbines	86	ASU	offsite
Steam turbines	43	Gas production	
		CCU	
Sum		**Sum**	

  Gross power production: 129 MW_e

- The filtrate from the soot water filtration is mostly recycled. Excess water is stripped in a sour water stripper and treated in the central refinery waste water treatment facility.

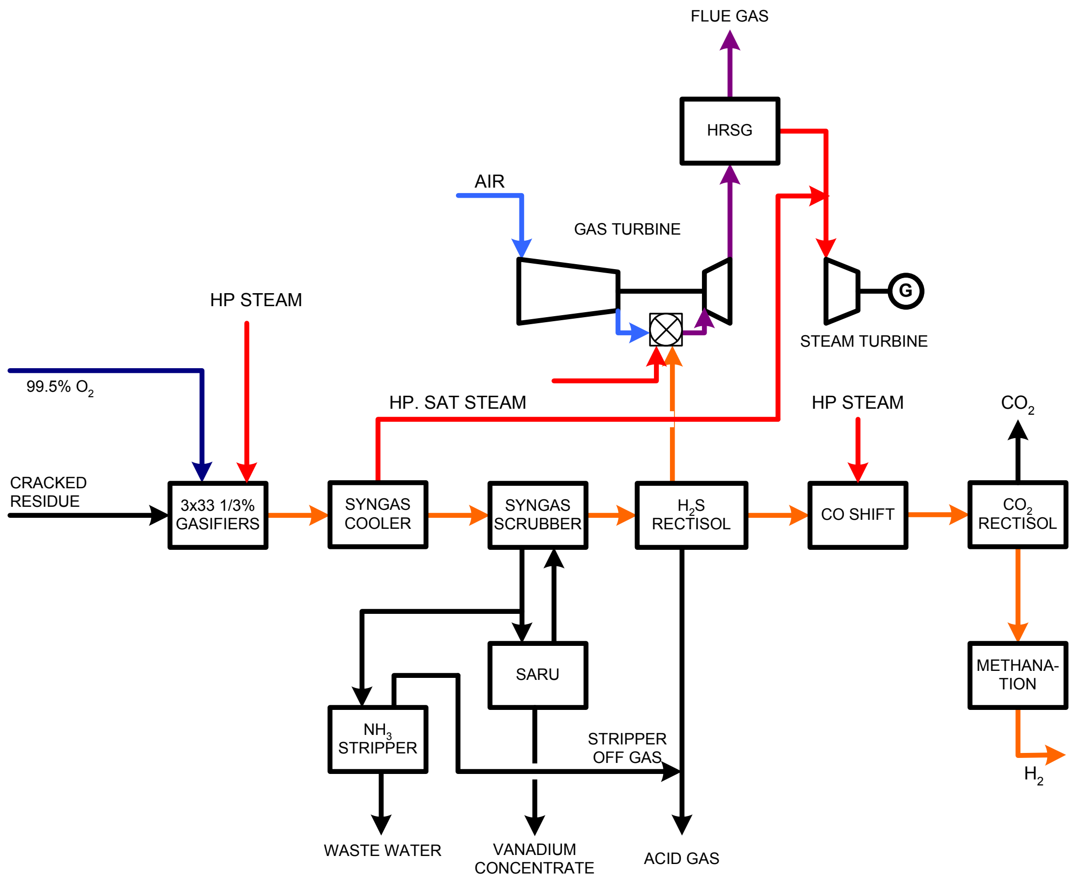

Figure 3-11
Block Flow Diagram, Pernis[6]

Operating history

There is not much operating history of this plant documented in the public domain. "The objective of 100% availability of syngas for the hydrogen manufacture is met." [de Graaf, 2000]. The single string availability is about 98%. Later information received in 2006 confirms that this has continued to be the case over the intervening period.

[6] SARU = Soot Ash Recovery Unit

ISAB, Priolo, Sicily

Plant description

The nominal 512 MW_e IGCC power plant which gasifies asphalt from the ISAB refinery in Priolo, Sicily was the first of three IGCCs to be built in Italian oil refineries at the end of the 1990s. The project was implemented by ISAB Energy, a joint venture of ERG Petroli and Mission Energy (USA). The plant went into commercial operation in April of 2000.

The principal characteristics of the plant design are as follows:

- **Air Separation Unit**: The oxygen is manufactured in two 1850 t/d ASUs owned and operated by Air Liquide. The plant has no air side integration with the gas turbine.

  The oxygen purity is 95% and there is a small capacity of liquid storage.
- **Oil gasification**: The gasification plant consists of 2 x 50% GEE oil gasifiers with integrated water quench. There is no spare gasifier.

  The feedstock is supplied directly from the upstream ROSE deasphalting unit. Back up feedstock can be drawn from storage.

  The **gasifier** itself operates at 67 barg (970 psig) and a temperature of typically about 1300°C (2400°F). The carbon conversion is about 99.5%. The unconverted carbon together with the vanadium rich ash is removed from the gas in the quench and a subsequent syngas scrubber.

  The syngas cooling to about 240°C (450°F) takes place in the quench section of the gasifier.

  The unconverted carbon is extracted from the soot water and recycled to the gasification reactor with the gasifier feed.
- The **Acid gas removal** consists of a COS hydrolysis and an MDEA wash. The clean syngas used as gas turbine fuel has a residual sulfur content of about 40 ppmv (estimated value only).

  The sour gas is processed to elemental sulfur in a dedicated oxygen-blown Claus unit. The Claus tail gas is hydrogenated and washed before being incinerated and discharged to the atmosphere.

  The clean, high pressure syngas is run through a gas expander for power recovery (5 MW_e). It is then saturated with water vapor.
- The **Combined cycle unit** is based on two Siemens V94.2K gas turbines each with its own HRSG and a steam turbine. Nitrogen is added to the syngas for NO_x reduction purposes. The HRSG is equipped with a selective catalytic reduction (SCR) stage for NO_x reduction when the gas turbine operates on the distillate back up fuel.

  The electrical energy balance is as follows:

Production	**MW$_e$**	**Consumers**	**MW$_e$**
Gas turbines		ASU	offsite
Steam turbines		Gas production	30
		CCU	11.8
Sum	**562.6**	**Sum**	**41.8**

Net power production (without ASU): 520.8 MW$_e$

- The **emissions** as permitted are [Farina & Collodi, 2000]
  Flue gas (@15% O_2 dry basis)
  NO_x < 30 mg/Nm³ (<15 ppmv)
  SO_x <10 mg/Nm³ (<3.5 ppmv)
  PM < 10 mg/Nm³
- The "gray water" from which the soot has been extracted is mostly recycled. Excess water is stripped in a sour water stripper and treated in the central refinery waste water treatment facility.

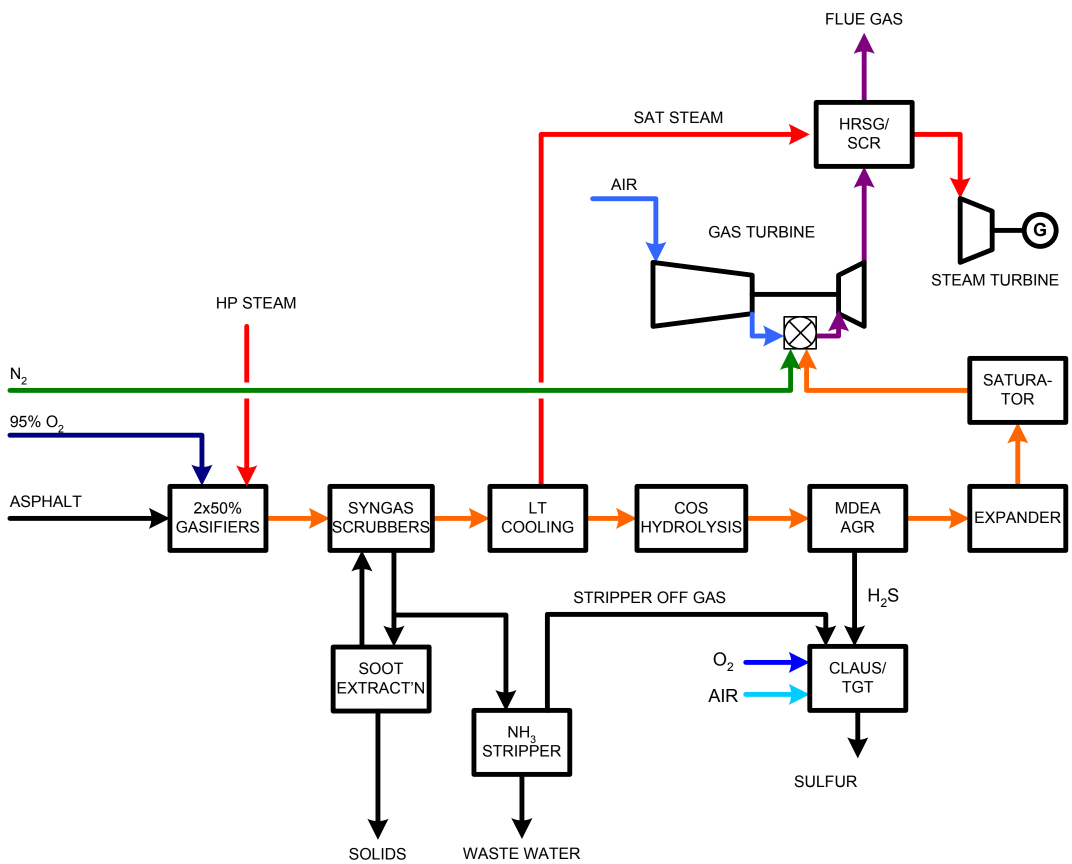

Figure 3-12
Block Flow Diagram, ISAB Priolo

Operating history

The annual availabilities achieved at the ISAB Priolo IGCC are shown in Figure 3-13.

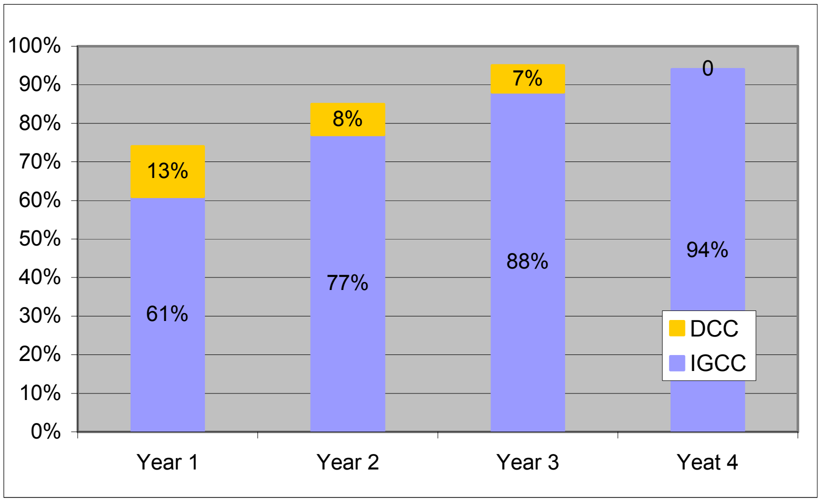

Figure 3-13
Annual on stream times at ISAB Priolo

Important issues include the following: [Collodi, 2001]

- Depositing of nickel in the gas turbine burners. The nickel is transported through the MDEA wash to the gas turbine in the form of nickel carbonyl, a gaseous compound not removed by the MDEA. In a subsequent plant in northern Italy (Sanazzarro) [de Graaf, 2002] provision has been made to remove the nickel carbonyl on activated carbon.
- The syngas produced had a higher hydrogen content that originally expected. Considerable care and additional testing was required before the gas could be used in the gas turbine.

Sarlux, Sarroch, Sardinia

Plant description

The nominal 550 MW_e IGCC (gross output) power plant, which gasifies refinery residues from the Saras refinery in Sardinia is the largest of three IGCCs built in Italian refineries at the end of the 1990s. In addition to the power produced the plant also supplies about 40000 Nm^3/h hydrogen and 185 t/h steam for process use in the refinery.

The project was implemented by Sarlux SpA, a joint venture between Saras S.a.r.l. and Enron (USA). The plant went into commercial operation in January 2001.

The principal characteristics of the plant design are as follows:

- **Air Separation Unit**: The oxygen is manufactured in two 2x 2300 t/d ASUs owned and operated by Air Liquide. The plant has no air side integration with the gas turbine. Oxygen purity is 95%. There is a small amount of liquid oxygen storage.

- **Oil gasification**: The gasification plant consists of three 33 1/3% GEE oil gasifiers with integrated water quench. There is no spare gasifier.

  The feedstock is supplied directly from the upstream visbreaker unit. Back up feedstock can be drawn from storage.

  The **gasifier** itself operates at 38 barg (550 psig) and a temperature of typically about 1300°C (2400°F). The carbon conversion is about 99,5%. The unconverted carbon together with the vanadium rich ash is removed from the gas in the quench and a subsequent syngas scrubber.

  The syngas cooling to about 240°C (450°F) takes place in the quench section of the gasifier.

  The unconverted carbon is extracted from the soot water and recycled to the gasification reactor with the gasifier feed.

- The **Acid gas removal** consists of a COS hydrolysis and a Selexol wash. The clean syngas used as gas turbine fuel has a residual sulfur content of about 30 ppmv (estimated value).

  The sour gas is processed to elemental sulfur in a dedicated oxygen-blown Claus unit. The Claus tail gas is hydrogenated and recycled back to the Selexol unit. The overall sulfur recovery for the IGCC is over 99.5%.

  40000 Nm^3/h hydrogen is withdrawn from the Syngas using a membrane separator. The final purification to > 99 mol% takes place in a pressure swing adsorption (PSA) unit.

  The clean syngas is saturated with water vapor. The saturated syngas has a lower heating value (LHV) of about 1700-1850 kcal/kg and is fed to the gas turbine at 20 barg (300 psig) and 200°C (400°F).

- The **Combined cycle unit** is based on three GE 9E gas turbines each with its own HRSG and a steam turbine. Nitrogen is added to the syngas for NO_x reduction purposes.

  100 t/h MP and 85 t/h LP steam from the HRSG is exported to the refinery

  The electrical energy balance is as follows:

Production	**MW_e**	**Consumers**	**MW_e**
Gas turbine (3x)	136.3	ASU	60
Steam turbine (3x)	50.8	Gas production	22.6
		CCU	10.2
		Balance of plant	22.5
Sum	**561.3**	**Sum**	**115.3**

  Net power production: 446.0 MW_e

- The **emissions** as permitted are [Collodi & Jones, 1999]

  Flue gas (@15% O_2 dry basis)

  NO_x < 60 mg/Nm^3

  SO_x <60 mg/Nm^3

  CO< 25 mg/Nm^3

  PM < 10 mg/Nm^3

- The "gray water" from which the soot has been extracted is mostly recycled. Excess water is stripped in a sour water stripper and treated in the central refinery waste water treatment facility.

  Downstream the biotreater: COD < 250 mg/l

  BOD_5 < 120 mg/l

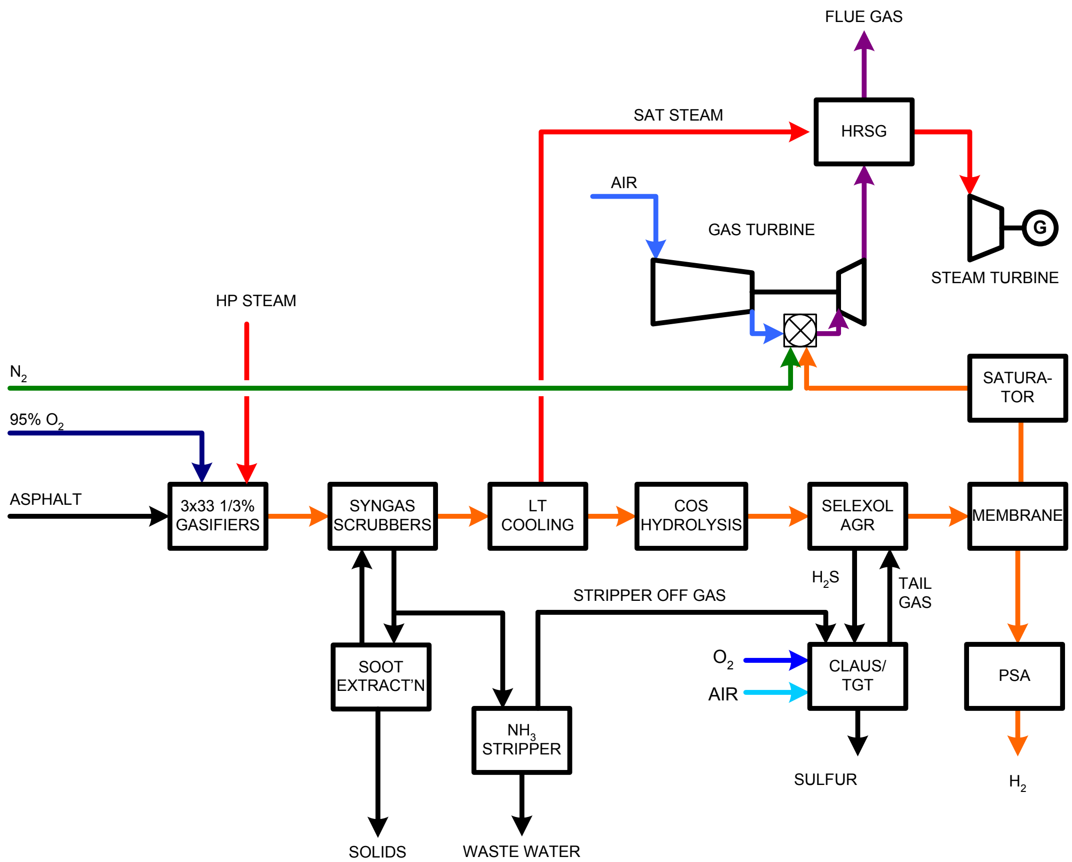

Figure 3-14
Block Flow Diagram, Sarlux

Operating history

The annual availabilities achieved at Sarlux are shown in Figure 3-15.

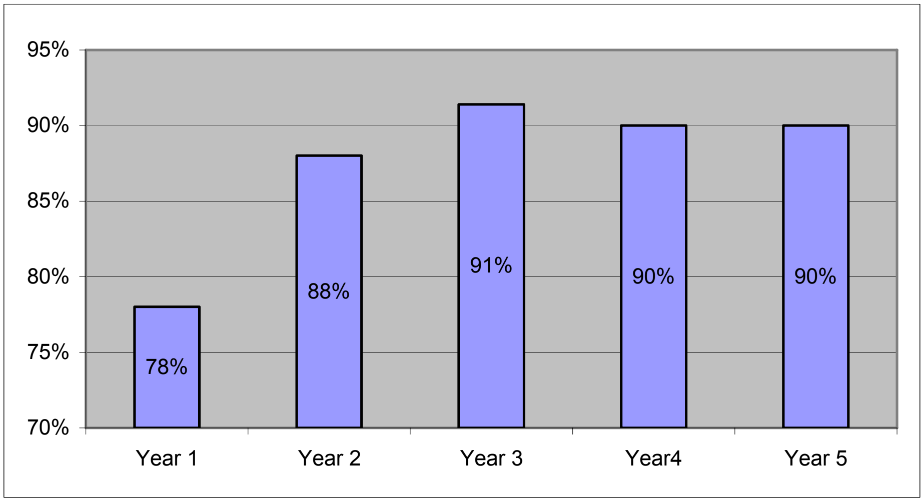

Figure 3-15
Annual on stream time at Sarlux

Important issues include the following: [Collodi, 2001]

- Carry over of Selexol solution into the syngas damaged the membranes used to extract hydrogen for the refinery.

api Energia, Falconara, Italy

Plant description

The nominal 250 MWe IGCC power plant which gasifies refinery residues at the api refinery in Falconara is the smallest of three IGCC built in Italian oil refineries at the end of the 1990s. The plant supplies 65 t/h process steam to the refinery, but does not supply any hydrogen. The project was implemented by api Energia, a joint venture of api, ABB and Texaco.

The plant went into commercial operation in 2000.

The principal characteristics of the plant design are as follows:

- **Air Separation Unit**: The oxygen is manufactured in a plant owned and operated by api Energia, which was supplied by Praxair. There is no air side integration with the gas turbine. The oxygen compression takes place in the gas phase.

  There is no liquid oxygen storage. Liquid nitrogen storage is available.
- **Oil gasification**: The gasification plant consists of two 50% GEE oil gasifiers with integrated water quench. There is no spare gasifier.

  The feedstock is supplied directly from the upstream visbreaker unit. Back up feedstock can be drawn from storage.

  The **gasifier** itself operates at 65 barg (930 psig) and a temperature of typically about 1300°C (2400°C). The carbon conversion is about 99.5%. The unconverted carbon together with the vanadium rich ash is removed from the gas in the quench and a subsequent syngas scrubber.

The syngas cooling to about 240°C (450°F) takes place in the quench section of the gasifier.

The unconverted carbon is extracted from the soot water and recycled to the gasification reactor with the gasifier feed.

- The Acid gas removal consists of a COS hydrolysis and a Selexol wash. The clean syngas used as gas turbine fuel has a design residual sulfur content of < 50 ppmv (typically achieve 40-45 ppmv S in summer and 10-15 ppmv in winter).

  The sour gas is processed to elemental sulfur in a dedicated oxygen-blown Claus unit. The Claus tail gas is hydrogenated and washed before being incinerated and discharged to the atmosphere.

  The clean, high pressure syngas is run through a gas expander for power recovery. It is then saturated with water vapor.

- The **Combined cycle unit** is based on one Alstom (formerly ABB) 13E2A gas turbine with HRSG and steam turbine. Nitrogen is added to the syngas for NO_x reduction purposes. The HRSG is equipped with a selective catalytic reduction (SCR) stage for NO_x reduction

  The HRSG exports 65 t/h steam to the refinery

  The electrical energy balance is as follows:

Production	**MW_e**	**Consumers**	**MW_e**
Gas turbine	190	ASU	
Steam turbine	93	Gas production	
		CCU	
Sum	**283**	**Sum**	**42**

  Net power production: 241 MW_e

- The “gray water” from which the soot has been extracted is mostly recycled. Excess water is stripped in a sour water stripper and treated in the central refinery waste water treatment facility.

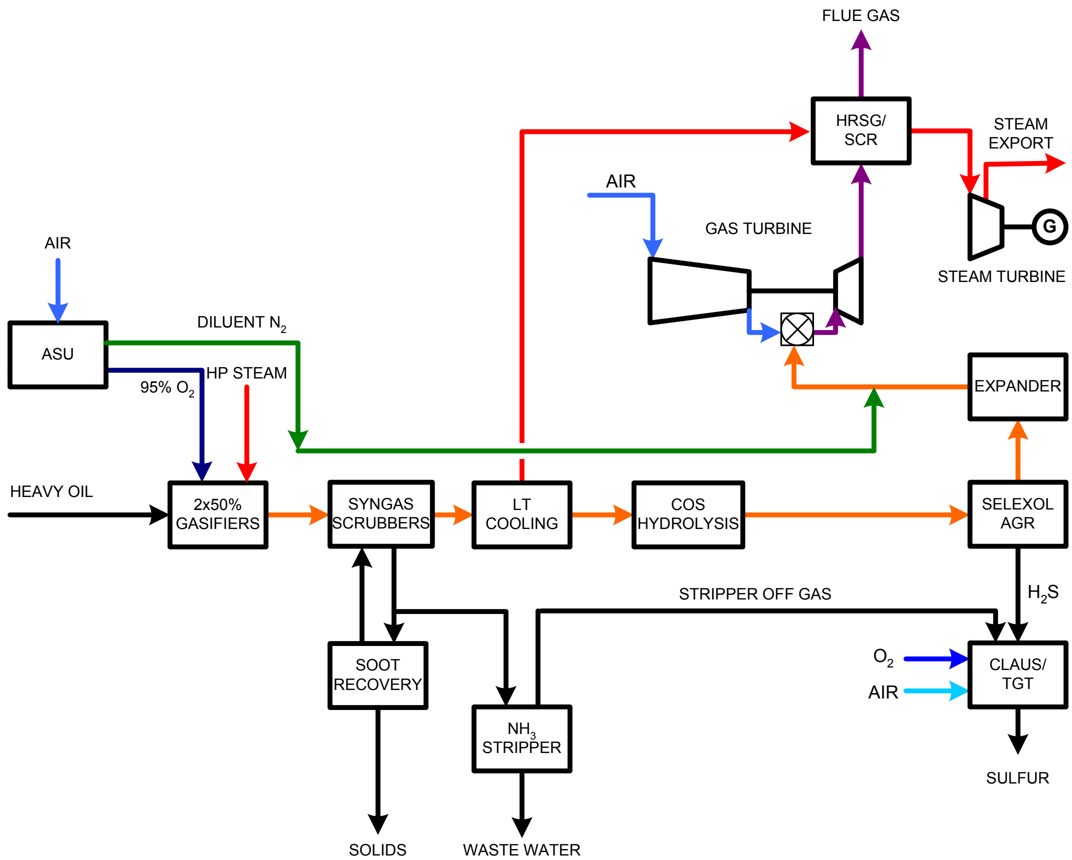

Figure 3-16
Block Flow Diagram, Falconara

Operating history

The annual availabilities achieved in Falconara are shown in Figure 3-15.

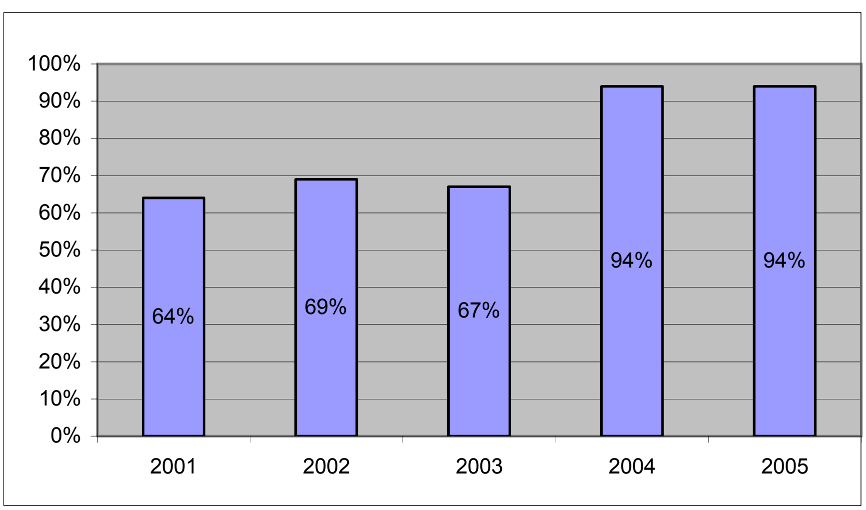

Figure 3-17
Annual on stream time in Falconara

Early problems included corrosion in the Selexol unit attributable to formic acid from the COS hydrolysis unit being vaporized in the regenerator and condensing in a “cold finger” [Sharp et al., 2002].

Important issues addressed in a major turnaround in 2003 are discussed in the paper by Arienti et al. [2005]. These include the following:

- Replacing the electric motor of the ASU air compressor. Sea water has been used for cooling. Corrosion led to moisture entering the windings.
- Replacing the inlet filter for the air compressor of the gas turbine. Carry through of sea water through the filter caused deposits of salt on the blades of the GT air compressor with resulting loss of performance.
- Change of metallurgy in areas of the oxygen system and the gray water system.
- Upgrading of the instrumentation to avoid spurious trips.
- Improvement of the IGCC master controller, to reduce flaring during load changes and improve trip management.
- Improvement of the steam turbine control system, which has provided an additional 5MW output.

Discussions during a Gasification Users’ Association visit in 2006 showed that while ammonium sulfate/bisulfate deposition on heat exchanger surfaces downstream the SCR are considered to be a problem, they have not significantly impacted availability. Cleaning is scheduled to coincide with gas turbine inspection intervals.

Nippon Oil, Negishi, Japan

Plant description

The 350 MW_e IGCC plant which gasifies refinery residues from the NOC refinery in Negishi (Yokohama) was taken over into commercial operation in June 2003.

The principal characteristics of the plant design are as follows:

- **Air Separation Unit**: The oxygen is manufactured in a 2300 t/d oxygen plant owned and operated by NOC, which was supplied by Air Liquide. There is no air side integration with the gas turbine.
- **Oil gasification**: The gasification plant consists of two 50% GEE oil gasifiers with integrated water quench. There is no spare gasifier.

  The 2000 t/d asphalt feedstock is supplied directly from the upstream unit. Low sulfur fuel from storage is used for start up and shut down to minimize sulfur emissions while flaring.

  The **gasifier** itself operates at 70 barg (1000 psig) and a temperature of typically about 1300°C (2400°F). The carbon conversion is about 99.5%. The unconverted carbon together with the vanadium rich ash is removed from the gas in the quench and a subsequent syngas scrubber.

  The syngas cooling to about 240 °C (450 °F) takes place in the quench section of the gasifier.

The unconverted carbon is extracted from the soot water and recycled to the gasification reactor with the gasifier feed.

- The **Acid gas removal** consists of a COS/HCN hydrolysis followed by an NH_3 scrubber. An ADIP (amine) wash is used for desulfurization. The clean syngas used as gas turbine fuel has a residual sulfur content estimated to be about 15 ppmv.

  The sour gas is processed to elemental sulfur in a dedicated oxygen-blown Claus unit. The Claus tail gas is hydrogenated and washed in a SCOT unit before being incinerated and discharged to the atmosphere.

- The **Combined cycle unit** is based on a Mitsubishi 701F gas turbine with HRSG and steam turbine. Nitrogen is added to the syngas for NO_x reduction purposes.

  The HRSG is equipped with a selective catalytic reduction (SCR) stage for NO_x reduction.

  The electrical energy balance is as follows:

Production	MW_e	Consumers	MW_e
Gas turbine		ASU	
Steam turbine		Gas production	
		CCU	
Sum	**431**	**Sum**	**89**

  Net power production: 342 MW_e

- The **emissions** as achieved are

  CCU Flue gas: 16% O_2, < 2.6 ppm NO_x, <2.0 ppm SO_x, < 1.4 mg/Nm³ PM

  Claus: 8% O_2, < 20 ppm NO_x, <90 ppm SO_x, < 6.7 mg/Nm³ PM

- The "gray water" from which the soot has been extracted is mostly recycled. Excess water is stripped in a sour water stripper and treated in a further waste water treatment facility before being discharged to the sea.

  COD <= 8 mg/l, T-N =< 5 mg/l, SS=< 10 mg/l

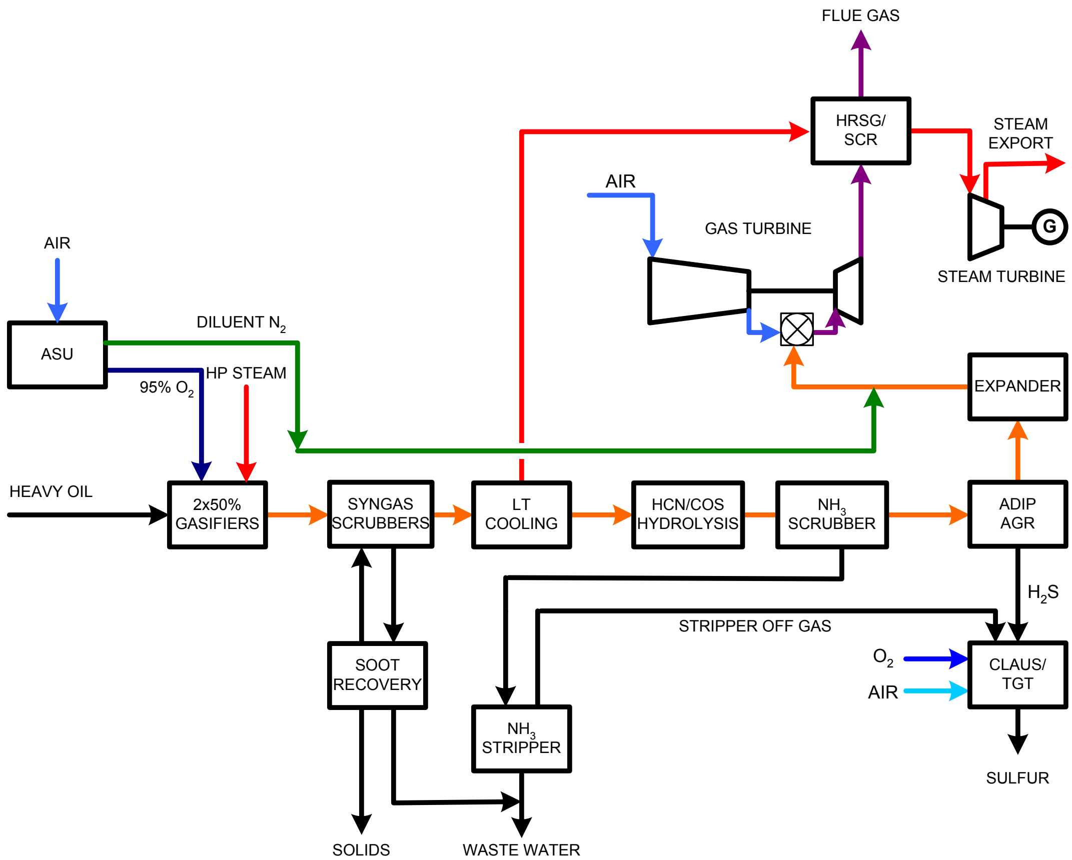

Figure 3-18
Block Flow Diagram, Negishi

Operating history

Yamaguchi [2004] lists the major causes of unplanned outage (total 16%) during the first year of operation as follows:

- Repair to the rotor of the ASU air compressor (9.9%). There was no spare on site so the damaged rotor had to be returned to the manufacturer in Europe for repair.
- Other ASU troubles (1.4%)
- Gasifier feed injector replacements (0.9%)
- Gasification “other troubles” (1.4%)
- CCU troubles (2.4%)

4
EXPERIENCE IN OTHER GASIFICATION PLANTS

Eastman, Chemicals, Kingsport, TN

Plant description

Eastman Chemicals' Kingsport, TN coal gasification plant has been in operation since 1983. The plant serves to manufacture methanol and carbon monoxide, the basic building blocks for the manufacture of acetic acid and a large range of other chemical products. Since the operation of the total Kingsport chemical complex is dependant on the uninterrupted supply of carbon monoxide, which cannot be stored, plant availability receives the highest priority.

This plant was the first commercially licensed Texaco coal gasification plant.

The principal characteristics of the plant design are as follows:

- **Air Separation Unit**: The oxygen is supplied "over the fence" from a plant owned and operated by Air Products. The oxygen purity is 99.5%. The air separation unit also provides high purity nitrogen for purging purposes.

  The facility includes liquid oxygen storage with the ability to provide uninterrupted supply to the gasifier, even in the event of an air compressor trip. The plant is equipped with LOX storage capacity. Liquid nitrogen storage is available.

- **Coal gasification**: The plant is equipped with two 100% GEE Quench Gasifiers, one of which is used as a spare reactor so as to permit refractory maintenance without any interruption of production.

  The **slurry preparation** takes place in two 60% rod mills. The slurry is stored in an agitated tank with a capacity sufficient to bridge an interruption of the rod mill operation. Two Geho membrane pumps feed the slurry to the gasifier.

  The **gasifier** itself operates at 70 barg (1000 psig) and a temperature of about 1500°C. (2730°F).

  The **synthesis gas cooling** takes place in the quench section of the reactor. The gas is quenched to about 245°C (470°F) and saturated with water vapor. This water vapor saturation is sufficient for the subsequent CO shift without additional steam addition. Simultaneously the majority of the particulate matter is removed from the gas.

  The slag leaves the quench chamber sump via a slag crusher and lock hoppers.

  Additional **gas pre-treatment** takes place in a scrubber, where ammonia, HCl and remaining particulate matter are removed from the gas. The scrubber outlet temperature is about 245°C (470°F).

- The **Acid gas removal** and other conditioning steps start with a partial **raw gas shift** (approx. 1/3rd of the gas) in order to adjust the H_2:CO ratio of the gas to that required of the methanol synthesis.

After further cooling, the gas is passed over a bed of activated charcoal for **mercury removal**. (Complete mercury removal from the gas is an absolute requirement for the downstream chemical production plants, which include products for the photographic industry.)

The acid gas removal takes place in a two stage Rectisol wash. The residual sulfur content from the first stage is 0.1 ppmv (total S). CO_2 is removed in a second stage and discharged to the atmosphere. The Rectisol unit is operated at sub-zero temperatures and therefore requires a refrigeration plant.

The sour gas is processed in a Claus unit to liquid sulfur. The Claus tail gas is treated in a SCOT plant before being incinerated and discharged to atmosphere.

- In the **Methanol Synthesis** up to about 600 t/d methanol is produced. The methanol is subsequently distilled to achieve the required specification. In addition to the methanol production carbon monoxide is also produced for the manufacture of acetic anhydride.

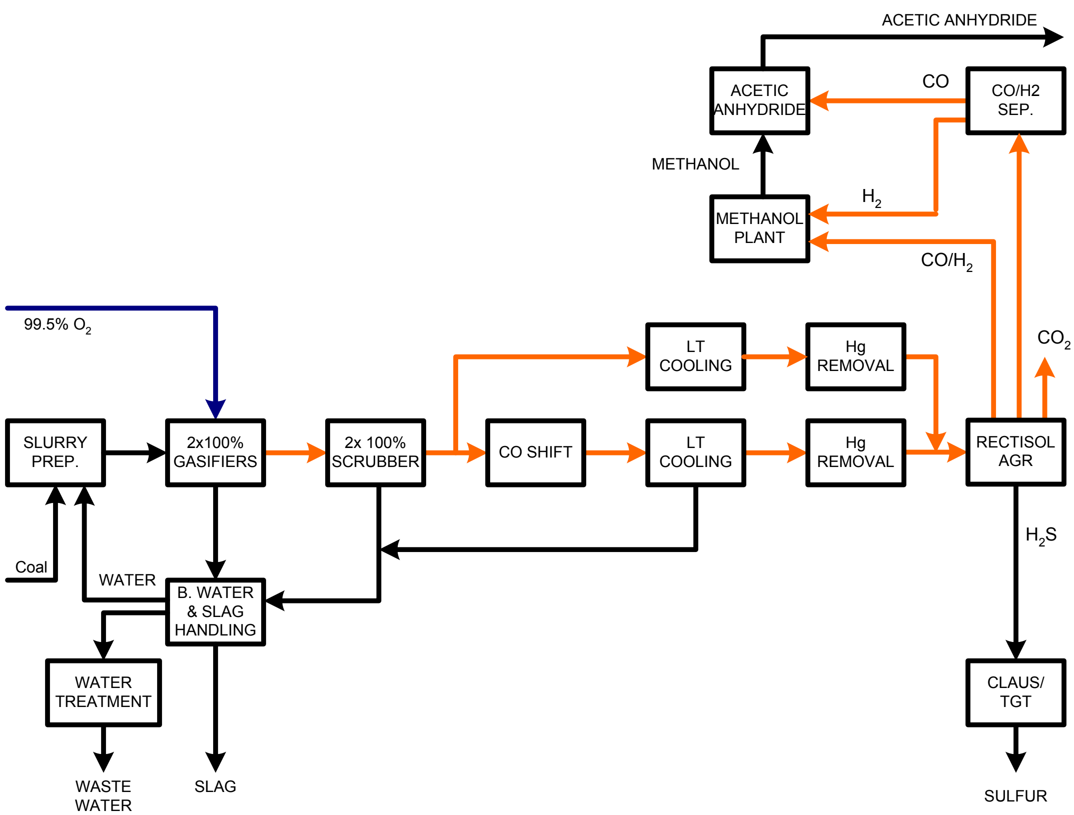

Figure 4-1
Block Flow Diagram, Kingsport

Operating history

The annual forced outage rates achieved in Kingsport are shown in Figure 4-2.

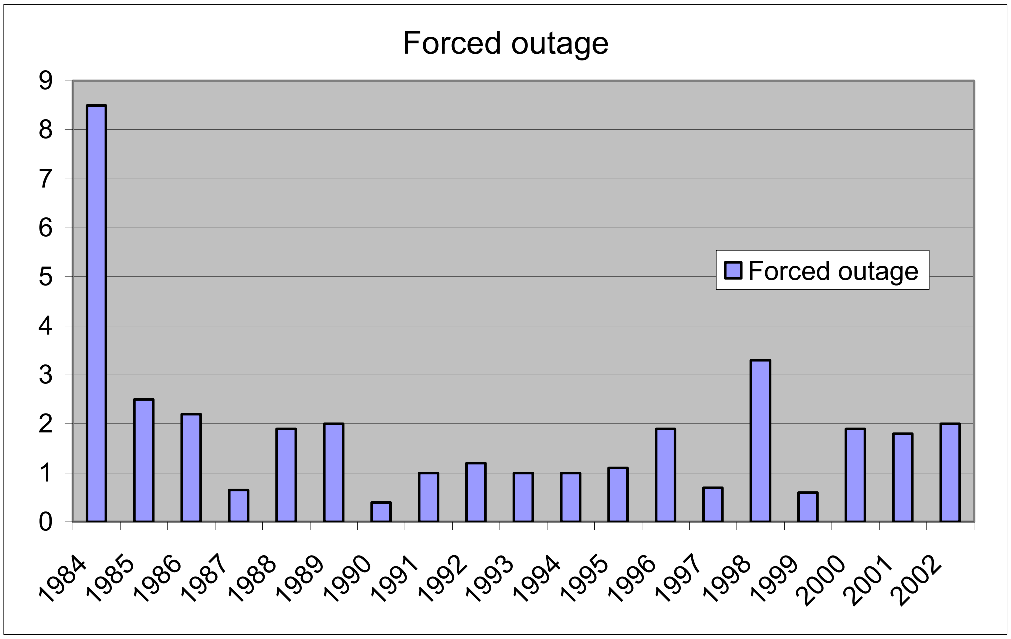

Figure 4-2
Kingsport Forced Outage Rates

The outage rates shown in Figure 4-2 are based on the use of a spare gasifier. The spare reactor is maintained on hot standby. Failure modes of e.g. the gasifier feed injector are well understood and continuously monitored, so that the spare rector can be brought on line before the failure occurs.

The amount of outage time in terms of production is very low. Apart from the spare reactor and its immediately associated equipment nothing else is spared beyond normal practice (e.g. pumps). Thus although these figures of about 98% overstate the performance of the gasifier, they are real and representative for the rest of the plant.

The use of a spare reactor masks a certain amount of maintenance activities in the gasifier area. The main cause of problems masked this way tend to be in the black water circuit and the slag removal system [Discussion in Kingsport, 2005]

Eastman operates the gasification facility on a 3-year maintenance cycle. During the most recent 3-year cycle (Sept 2001 – Sept 2004) the plant was on-stream 97.97% of the time. Eastman estimates that single train gasifier availability was 88-90% during that period. [Trapp presentation to CoalFleet, July 2005]

Coffeyville Resources Ammonia Plant, Coffeyville

Plant description

The Coffeyville Resources ammonia plant was originally built by Farmland Industries, a leading fertilizer manufacturer, in 1997. As part of a strategy to accelerate the project implementation, Farmlands purchased the equipment from the mothballed 100 MW_e Cool Water demonstration plant and erected it next to the Coffeyville refinery in Kansas. The mechanical completion was achieved in March 2000. The first reactor start took place in July and the first ammonia produced at the end of August 2002.

The plant is now operated by Coffeyville Resources.

The principal characteristics of the plant design are as follows:

- **Air Separation Unit**: The oxygen is supplied "over the fence" from a plant owned and operated by BOC Gases. The oxygen compression takes place in the gas phase to a pressure of 60 bar (850 psig). The air separation unit also provides high purity nitrogen (< 40 ppmv O_2) for the ammonia synthesis.

  The facility does not include any liquid oxygen storage. Liquid nitrogen storage is available.
- **Coal gasification**: The plant is equipped with two 100% GEE Quench Gasifiers, one of which is used as a spare reactor so as to permit refractory maintenance without any interruption of production. The original Cool Water plant had a "main" reactor with radiant cooler and a smaller spare reactor fitted with a quench. Since for the production of hydrogen for ammonia manufacture the quench cooling integrates better with a raw gas CO shift, the radiant cooler on the main reactor was replaced by a quench chamber.

  The Cool Water plant was originally conceived for a variety of coals. In Coffeyville the plant runs on petcoke from the neighboring refinery. However a flux is added to the coke since the latter only has a small amount of high melting point, vanadium-rich ash.

  The **slurry preparation** takes place in two 60% rod mills. The slurry is stored in an agitated tank which provides back up capacity to cover an interruption of rod mill operation. Two Wilson-Schneider reciprocation pumps charge the slurry to the gasifier.

  The **gasifier** itself operates at 43 barg (620 psig) and a temperature of about 1370ºC (2500°F).

  The **synthesis gas cooling** takes place in the quench section of the reactor. The gas is quenched to about 245°C (473ºF) and saturated with water vapor. This water vapor saturation is sufficient for the subsequent CO shift without further steam addition. Simultaneously the majority of the particulate matter is removed from the gas.

  The slag leaves the quench chamber sump via a slag crusher and lock hoppers.

  Additional **gas pre-treatment** takes place in a scrubber, where ammonia, HCl and remaining particulate matter are removed from the gas. The scrubber outlet temperature is about 235°C (450°F).
- The **Acid gas removal** and other conditioning steps start with a raw gas shift in order to produce more hydrogen for the ammonia synthesis.

Since COS is largely converted to H_2S in the shift, the Selexol wash is capable of achieving the required degree of desulfurization without an upstream COS hydrolysis. The Selexol wash is built as a two stage system. The first stage desulfurized the gas to < 1 ppm H_2S and <1 ppm COS.

The acid gas is delivered to battery limit to another operator, who processes it to ammonium thiosulfate fertilizer [Barkley, 2003].

The second stage removes about 85% of the CO_2. Part of this CO_2 is available at about 10 barg and is compressed to about 260 barg (3750 psig) for the urea ammonium nitrate (UAN) plant. The Selexol plant is operated at sub-ambient temperatures and therefore requires a refrigeration plant.

The raw hydrogen from the Selexol unit still contains about 5% CO_2 and is purified to >99.9% in a pressure swing adsorption unit.

- In the **synthesis** 1100 st/d ammonia and 1750 st/h UAN (nameplate capacities) are produced.

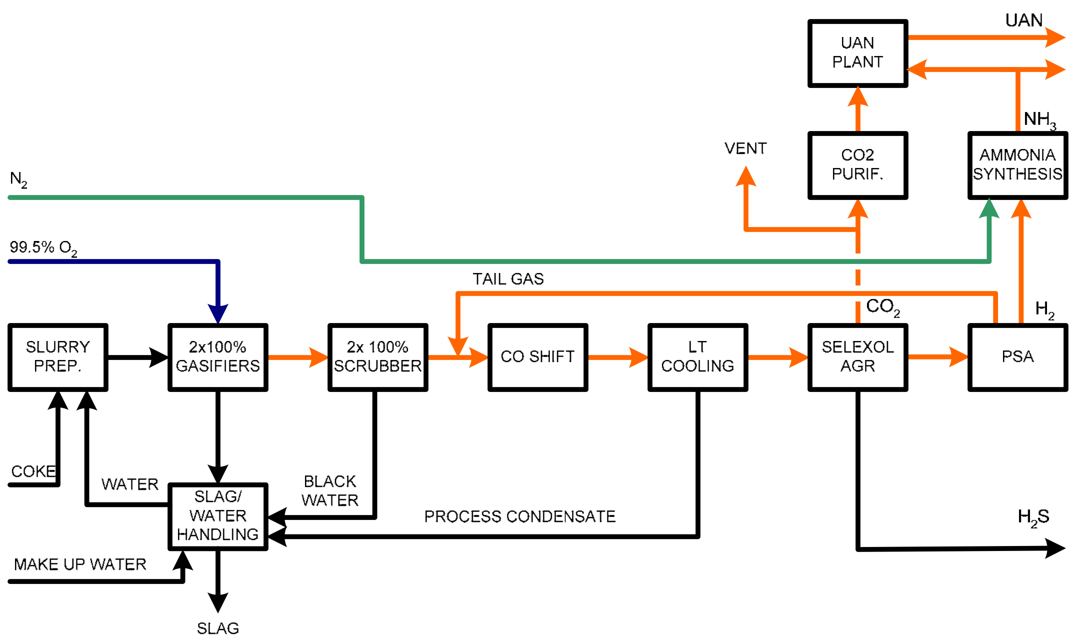

Figure 4-3
Block Flow Diagram, Coffeyville

Operating history

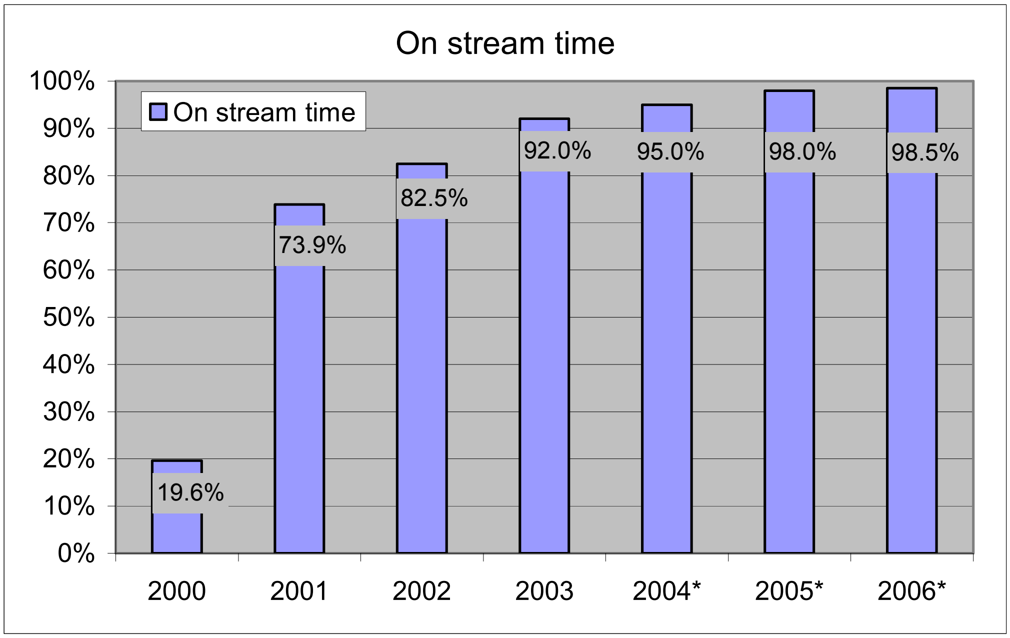

Figure 4-4
Coffeyville on-stream times

[*2004-2006 excluding turnaround, 2006 till September]

The major issues described by Barkley include much time lost in the downstream units of ammonia synthesis and its associated refrigeration plant. Of a total of 466 hours downtime in 2003, he reports the allocation as follows:

Ammonia Plant	**27.7%**
ASU	**18.5%**
Entrainment	**18.1%**
Waste heat boiler	**6.9%**
Feed Injector Leaks	**6.7%**
Refrigeration Compressor	**6.5%**
AGR	**6.4%**
Dip tube/quench ring	**4.9%**
Miscellaneous	**4.3%**

The plant design was for1120 stpd ammonia. "Currently the plant routinely makes 1240 stpd of ammonia" [Barkley, 2006]. In the same paper Barkley points out that "Recognizing that most of the other costs [than coke and power] are essentially fixed, the on-stream factor is the most important variable in keeping production costs low. Given the current price of natural gas, and the high on-stream factor, Coffeyville Resources is the low cost producer of ammonia and UAN in North America."

Dakota Gasification, Beulah, North Dakota

Plant Description

The plant was constructed by American Natural Gas to manufacture Substitute Natural Gas (SNG) from lignite and came on stream in July 1984. It is now owned and operated by the Dakota Gasification Company (DGC), a subsidiary of Basin Electric Power Cooperative.

The principal characteristics of the plant design are as follows:

- **Air Separation Unit**: The oxygen is supplied by two parallel ASUs each rated for 3100 t/d. The oxygen compression takes place in the gas phase. Liquid oxygen storage with a vaporizer is provided as a back up. Liquid nitrogen storage is available.
- **Coal Gasification**: The plant is equipped with 14 Lurgi Mark IV gasifiers, originally intended as 12 operational with two spares.

  The **coal preparation** consists of crushing to a size of ¼”-2” range and screening the fines. The fines cannot be accepted by the gasifier and are fed to the neighboring Basin Electric power plant.

  The **gasifiers** were originally designed to process 18,500 t/d lignite and operate at approximately 460 psig (32 bar). While internal bed temperatures reach about 2,300 °F (1,260 °C) the exit temperature of the gas is much lower, being 400 °F (205 °C) after the close coupled wash cooler. The gasifier is operated in a non-slagging mode. 460 psig steam is raised in the cooling jacket of the gasifier.

  The **syngas cooler** is a vertical convection cooler, which reduces the temperature further to about 380 °F (195 °C). Part of the volatile matter in the gas is condensed to form gas liquor containing tars, oils as well as coal fines. This gas liquor stream is sent to the gas liquor separation for further processing.

  Part of the syngas is cooled further also generating steam. During this low temperature gas cooling additional gas liquor is formed. Part of this gas liquor is used in the wash coolers. The rest is sent directly to the gas liquor separation.

  Ash is withdrawn from the gasifier via a lock hopper, which discharges the ash into a sluiceway. Circulating water transports the ash to the ash handling area, where it is dewatered. Ash is transported to a landfill.
- The **acid gas removal** and other conditioning steps start with a partial **raw gas shift** (approx. 1/3rd of the gas) in order to adjust the H_2:CO ratio of the syngas to that required for the methanation. There are two trains each with three parallel reactors.

  The acid gas removal takes place in two parallel single stage Rectisol units. The clean gas contains a residual total sulfur content of 20 ppbv (0,02 ppmv). A pre-wash stage is incorporated to recover naphtha contained in the raw gas. The design of the Rectisol for Beulah did not make provision for any separation of H_2S and CO_2 both of which are contained in a single waste gas stream.

  The original plant design provided for the waste gas stream to be desulfurized in a Stretford liquid redox wash prior to final incineration in the plant’s auxiliary boilers. The Stretford unit never operated satisfactorily so the boilers were retrofitted with flue gas desulfurization in 1966. Since 2000, part of the waste gas is recovered as CO_2 and compressed to about 2750 psig (190 bar) and transported via pipeline to an enhanced oil recovery operation in Canada.

- The original design provided for all the syngas to be converted to substitute natural gas in a methanation unit. Later an ammonia synthesis unit was added. A small methanol unit covers the methanol make up requirement of the Rectisol unit.
- The **waste water treatment** of the gas liquor stream from the gasification unit must take account of the large organic and inorganic load. Phenols are separated out in the phenosolvan unit, before being purified and sold as an end product. The ammonia in the remaining gas liquor is separated out in the Phosam unit and also recovered for sale.

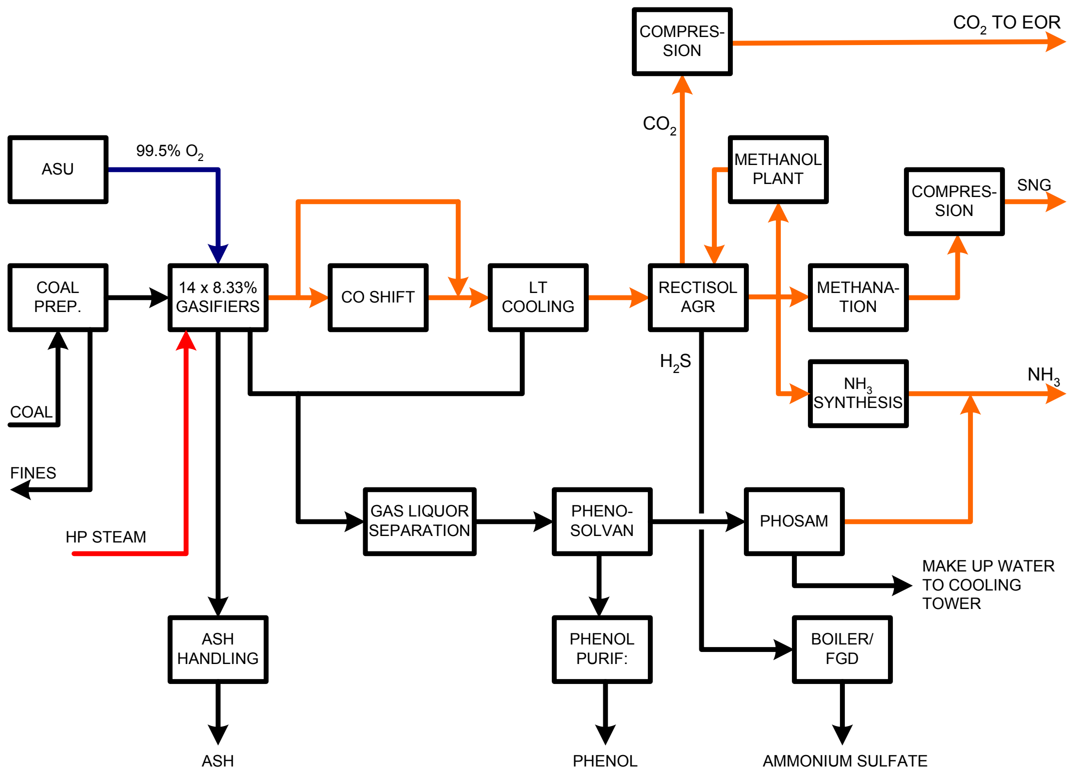

Figure 4-5
Block Flow Diagram of Beulah Gasification Plant

Operating History

Detailed operating statistics are not available in the public domain. The following table showing the number of days at zero production taken from the DOE, Office of Fossil Energy report [2006] provides an impressive record, but without knowing whether both trains or only one was in operation makes any detailed deductions on availability problematical.

Table 4-1
Number of Days at Zero Production By Year 1984 – 2005

[Courtesy DOE, Office of Fossil Energy]

Year	Days	Notes
1984	18	(Started Production on 7/27/84)
1985	1	
1986	0	
1987	0	
1988	18	
1989	0	
1990	0	
1991	4	
1992	0	
1993	0	
1994	0	
1995	0	
1996	7	Scheduled 'brown plant'
1997	0	
1998	0	
1999	0	
2000	0	
2001	0	
2002	0	
2003	0	
2004	48	Scheduled 'black plant' maintenance turnaround
2005	7	
	103	**Outage days out of 7,828 days since operations began.**
	98.7%	

The same DOE report includes a large number of lessons learned. Most of these are application specific, e.g. influence of Lurgi gasifiers on the coal preparation, influence of tars/naphtha on the Rectisol AGR, the extremely high degree of desulfurization demanded by the methanation and are unlikely to be applicable to a modern IGCC. They will therefore not be repeated here.

5
AVAILABILITY OF IGCC PLANT UNITS

This chapter analyses the causes of outages – particularly unplanned outages – on a section by section basis through these plants.

Air Separation Unit

General

Air separation units in the industrial gas industry have availabilities typically of about 98.5%. The non-available time typically consists of 1% planned outage and 0.5% forced outage. Within an IGCC complex the planned outage would be timed to coincide with other planned maintenance (e.g. burner inspections on the gas turbine) so that one would expect only 0.5% of outage time on IGCCs to show up as being attributable to the air separation plant. In fact the recorded outage in the four large coal-based IGCC units is much higher that this, reaching as much as 10% for some plants in some years (see below).

There are two commercial models for supplying the oxygen to an IGCC. The four large operating coal-based IGCCs have all opted for the "plant purchase" model, in which the IGCC operator purchases and operates his own ASU. A number of other gasification plants (including some refinery-based IGCCs) have opted for the "gas purchase" model, in which the ASU is built, owned and operated by an industrial gas company, which supplies the gaseous oxygen at pressure "over-the-fence".

Table 5-1 shows a summary of the ASUs in the IGCC/gasification industry.

The continuity of the oxygen supply is of central importance to a high availability in an IGCC or any other gasification plant. Historically those plants with gas supply contracts have tended to perform better in terms of reliability than the owner-operated units. This is generally attributed to the fact that the industrial gas companies employ O&M staff that have gained the specific ASU experience on their other sites, whereas in owner-owned plants this experience may have to be built up during the first few years of operation.

This is however certainly only part of the background. Another aspect is that owner-owned plants are typically purchased in a competitive bidding situation, where the successful (lowest cost) bidder is awarded the contract. In this situation it is difficult without a very detailed specification and/or supervisory engineering effort to avoid the vendor taking decisions which conform to the specification and his own budget, but may have availability implications at a later stage.

Table 5-1
Summary of ASUs in IGCC or other gasification plants

Plant	Capacity (mt/d)	$\%O_2$	Contract (plant/gas)	LOX storage	Supplier
Buggenum	**1780**	**95%**	**Plant**	**Yes**	**AP**
Wabash	**2050**	**95%**	**Plant**	**No**	**AL**
Polk	**1840**	**95%**	**Plant**	**No**	**AP**
Puertollano	**2400**	**85%**	**Plant**	**Yes**	**AL**
Pernis	**3175**	**99.5%**	**Gas**	**7 km pipe**	**AP**
ISAB	**2x1850**	**95%**	**Gas**	**Yes**	**AL**
Sarlux	**2x2300**	**95%**	**Gas**	**Yes**	**AL**
Falconara		**95%**	**Plant**	**No**	**Praxair**
Exxon, SI	**1600**		**Gas**		**AL**
Negishi	**2400**	**95%**	**Plant**	**No**	**AL**
Kingsport			**Gas**	**Yes**	**AP**
Coffeyville			**Gas**	**No**	**BOC**

Documented outage causes

The following illustrate some of the causes for documented ASU outage in IGCC and other gasification plants:

Air compressor inlet guide vanes: At Wabash the air compressor inlet guide vanes were identified "very early … as the biggest reliability issue for the main air compressor [Wabash final report]. , Polk has also experienced problems with inlet guide vanes.

Air compressor electric motor drive: In Falconara, where for the first two years the IGCC availability did not reach 70% availability, this motor was replaced. Numbers are not available, but it is clear that this must have been a major contributor to the lack of availability. Background to the problem was a decision to use sea water as cooling water for the motor, which created substantial corrosion problems ultimately leading to "water leakages from the cooler to the windings" [Arienti et al, 2005]. Sea water cooling for such a motor is unusual. Typically such motors have always been cooled with a closed circuit cooling system. The motor was subsequently replaced with a larger unit.

In Wabash there were considerable problems in the early plant life attributable to moisture entering the windings of the electric motor, although there was no outage time directly attributable to this cause. The reason for these problems was that the motor had not been designed for outdoor installation, despite it operating in an outdoor environment.

Air compressor rotor: Both Polk (2001) [McDaniel, 2001] and Negishi (2003) [Yamaguchi, 2004] suffered from damaged rotors on the air compressors. In both cases the rotors has to be returned to the manufacturers for repair. In both cases the loss of production was about 3 weeks or 9% of the year. In neither case was a spare rotor available on site. While a spare rotor would not have prevented the outage as such, it could have reduced the outage time to about one week, thus saving about 6% of annual production. Experience in chemical plants based on gasification is typically that spare rotors are maintained as “insurance spares” for all single train turbo-compressors.

Air compressor instrumentation: Instrumentation of the air compressor has been reported as a problem in Wabash, Polk, Coffeyville and other plants. General experience has shown that this can be an important source of outage.

Direct contact cooler: In Coffeyville the ASU had to be shut down on one occasion because of a black water break-through into the direct contact cooler, which subsequently caused the cold box to rime up. This was caused when a heat exchanger leaked black water into the cooling water. The process was later modified so that cooling water was always at a higher pressure than the black water [Barkley, 2003]. This incident was surprising, because the direct contact cooler is generally operated with a separate cooling water circuit from that of the main process plant as was the case here.

Molecular sieve valve selection: These automatic valves switch on a very short cycle and must be both robust and tight. Both Wabash and Buggenum have experienced problems.

Molecular sieve regeneration heater: Wabash has reported multiple and regular tube repairs on the regeneration heater. Similar experience on starting up a gasification-based ammonia plant has been reported to EPRI on an anonymous basis. Leakage is from the steam side to the regeneration gas side, thus introducing moisture to the molecular sieve at a point in time, when it is being regenerated. If not corrected quickly, this ultimately leads to moisture break-through to the cold box and the necessity to come off line to de-rime. While this did not cause any loss of production in the March 1998 – February 1999 “Operating Period” in Wabash, the anonymous project was not so fortunate. In one case the problem was definitely attributable to vibrations in this tubular heat exchanger, in the other case vibrations were the likely cause. A similar incident was recorded in Beulah.

Cold box leakages: Both Wabash and Polk, experienced piping leakages in the cold box area. Similar incidents are also known elsewhere. In each case it was necessary to remove a large portion of the perlite filling of the cold box in order to access the leakage area and make the repair. It is necessary during the repair time to keep the removed perlite dry (or requisition a new filling) and to ensure that it is dry when refilling the cold box. Furthermore one must include the time to bring the equipment from cryogenic temperatures back to ambient and cool down again after the repair. In Wabash faulty welds on a de-riming header caused an outage of 299 hours in the 3rd quarter of 1999 [Final Technical Report]. In Polk 410 hours of outage in March/April 2000 were caused by a faulty weld on an instrument connection [McDaniel, 2000]. In both cases careful analysis during the repair revealed other welds, which had to be repaired too. In a third case the leak was at a flange on a valve inside the perlite area. Piping stresses caused during cool down of the cold box pulled on the flange joint, causing it to leak under pressure. The loss of production was even longer than in Polk. This last case shows how important small details can be. Normal practice is to keep any flanges outside the perlite space and place them in a separate chamber insulated with rock wool or similar, which allows easy access. This is another issue, where attention needs to be paid not only to avoiding incidents, but also to minimizing their effects, if they should happen.

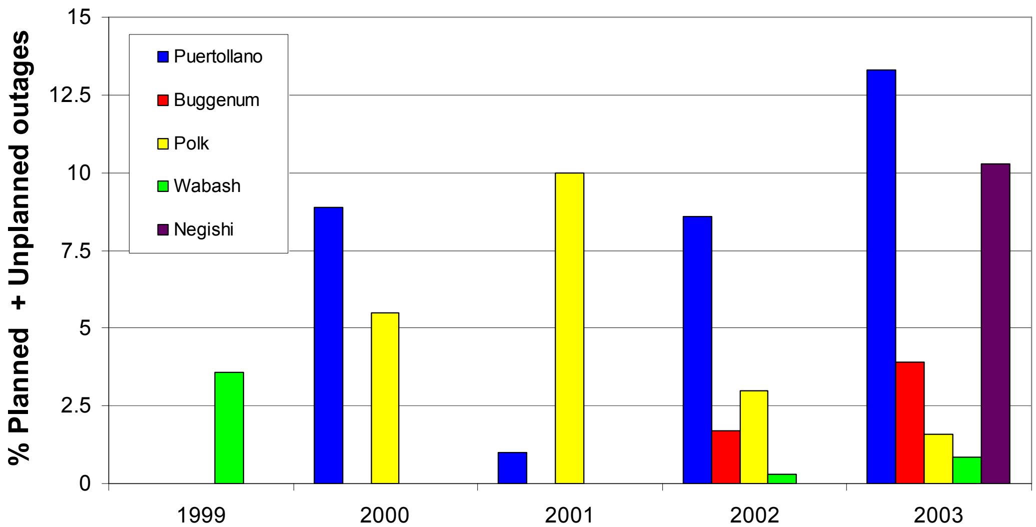

Figure 5-1
ASU Outages in Selected Plants

Liquid Oxygen Storage

The benefits of liquid oxygen (LOX) storage are fiercely debated. The purpose of such storage is to provide a temporary supply by vaporizing the stored LOX to bridge a short-term interruption of ASU operation. The most important design criterion is the volume of storage expressed in hours of production. The operator only has benefit from a LOX storage facility in relation to those outage periods that are shorter than the storage capacity, which would be typically 8 to 12 hours production. Clearly for a number of the outage incidents reported in the previous section, LOX storage would not have been able to prevent shutdown. And this is the main issue behind the debate.

In their final THERMIE report, Elcogas, which has LOX storage in its Puertollano plant, states that they would not build a LOX storage in a new plant. In two other plants, which do not have LOX storage, retrofitting a LOX storage facility has been examined as a measure to increase availability and in both cases it was rejected as not being able to pay for itself. In one case the majority of outage incidents were longer than a reasonable storage volume and therefore the number of occasions in which it would provide a benefit was strictly limited. In another case, Coffeyville reviewed the installation of LOX buffer storage capacity [Barkley, 2003], but subsequent upgrading of the instrumentation around the ASU reduced the outage time sufficiently to render the additional expense unjustified.

On the other hand other plants are extremely happy with their LOX storage. In one plant visited during the course of compiling this report, a total plant trip had been avoided the previous day because the LOX storage had cut in on an ASU trip. In Buggenum the gaseous oxygen (GOX) buffer was upgraded to improve the dynamics of the transient when the LOX storage cut in –

hardly something one would do if the system was not useful. For a 3900 t/d unit under construction in Canada, Opti and Air Liquide have reported that they plan to install a 2000 t (12 hours) LOX storage tank. The calculated benefit is to improve the ASU availability at full production from 98.7% to 99.5% [Rettger at al, 2004].

It would appear that LOX storage must be a project specific decision based on a number of factors, such as

- Stability of external power grid (e.g. millisecond voltage dips leading to trips of air compressor motor)
- Plant trainage concept (one of the biggest expenses of a plant trip is fuel costs for the restart, so if a multi-train plant can be kept operational at low load, then these costs can be largely avoided)
- Economics of dispatching the gas turbine on back-up fuel or dispatching the next-in-line plant in the operator's network (only relevant for IGCCs, not for chemical operations).

Gasification Unit

Feed system

The feed system as described here covers the feedstock preparation (rod mill and slurry handling or roller mill and drying) and feedstock pressurization (pumps or lock hoppers).

Slurry systems

The rod mill in Wabash was sensitive to the presence of foreign (metal) objects in the coal until a design change solved this problem. The rod mills were also a persistent cause of difficulty in Kingsport with five pinions failing in the period December 1997 to July 1998. Intensive work provided a solution and the problem has not reoccurred [Hrivnak, 2001].

Overall plant availability is protected to some degree by the existence of one or (in most plants) two slurry buffer tanks between the rod mills and the main slurry charge pump. Wabash did have some downtime attributable to a broken slurry tank agitator, which can certainly justify the two tank concept.

Polk is unusual in that it only has no spare pump, but the pump itself has not proved to be a major source of lost production. None the less a significant amount of downtime (start up delays) in Polk has been attributable to the slurry pumping system. This is less a matter of the pumps themselves, but more of arranging the suction piping such that the slurry does not settle in front of the pump during shutdown. In Coffeyville this is achieved by keeping both 100% pumps running at half speed in normal operation and only ramping up if one pump fails. This way there is always movement of slurry in the line.

Dry feed systems

Puertollano has a complicated feed mix system to ensure an accurate blend of coal and petcoke. Elcogas has determined that the degree of accuracy provided is not really necessary and that there is considerable scope for simplification in this area.

In contrast to the three train arrangement in Buggenum, Puertollano only has two 60% roller mills. This equipment requires regular maintenance and is listed as the third most important cause of outage [Garcia Peña, 2005]. Part of the high maintenance requirement is attributed to the properties of the petroleum coke feed. Even with such a problem the three train arrangement as in Buggenum would allow this maintenance to be carried out while the plant is still operating at full load.

Buggenum has reported bridging in the pulverized coal (PC) sluicing vessel as a critical item [Kanaar, 2002]. Problems in this area have however been resolved.

Gasifier

Burner

On slurry feed gasifiers, the burners or feed injectors have a limited life. This requires a change out at intervals that can vary between about 50 and 100 days. With good planning and operation, the down time of a reactor can be limited to about 8 hours. The effect on a single train unit may be a little more than this, because the downstream gas treatment system must then be restarted. Operation with two 50% gasifiers can alleviate this, since the gas treatment and CCU operation is maintained at 50%. When the second gasifier is brought back on line, ramping back up to 100% can be achieved much quicker than with a total restart.

For dry feed systems the lifetime of the burner (>20,000 hours) is sufficient that it has no influence on availability.

Reactor wall

Refractory lifetime is the other major availability restraint for those gasifiers which use it. This is probably the most important justification for Kingsport to have the spare gasifier. The typical interval between refractory repairs lies between 18 months and two years, although this figure is highly dependant on coal (slag) quality and operating temperature. (Individual cases are known of a refractory lining lasting three years, though not on a repeatable basis.) A refractory replacement including time to cool down and restart will be between three and four weeks. The ideal maintenance program would foresee scheduling the refractory replacement to coincide with gas turbine maintenance. As long as availabilities are below 80% the mismatch between the two schedules does not show up in a prominent manner.

For **water cooled membrane wall** systems the lifetime of the gasifier wall (>10 years proven, 25 years predicted) is sufficient that it has no influence on availability. In Buggenum the heat skirt at the bottom of the reactor chamber is refractory lined and this requires regular repair. Shell has taken this on board as a “lesson learned” and new units use water cooled skirt [Chhoa, 2005].

Specific localities in the membrane wall in Puertollano suffer from water leakage caused by local erosion. The root cause lies in the water distribution, rather than the syngas temperatures. Some wall tubes are connected to the bottom of the bottom header and these tubes are preferentially blocked by any particulate matter in the boiler water. The result is insufficient cooling of these tubes. Note that the existence of the particulate matter also raises the question of the quality of the boiler feedwater.

Coal Quality

If the coal quality changes, then generally this will also change the melting point of the ash. If this melting point increases, then it is necessary also to increase the operating temperature otherwise the slag will begin to solidify and start forming lumps. If no action is taken, this will ultimately lead to plugging the slag-tap. This phenomenon is valid for all types of slagging gasifiers.

Until about 2002 Buggenum experienced considerable problems with the formation of slag lumps in the bottom of the gasifier. This was primarily associated with unplanned changes in the quality of coal (ash) being processed. Improved operator training and better control over the coal procurement have eliminated this problem. Note that Eastman have also reported on the criticality of knowing what coal is being processed and adjusting the operating conditions to suit [Brooker, 2003].

Corrosion

Another problem specific to Puertollano is corrosion of “cold dead ends”. In localities connected to the syngas piping, where no flow is present to maintain a temperature over the dewpoint, then a corrosive sour condensate is produced. Typical locations are instrument connections or start up connections for e.g. purge nitrogen. Standard solutions to this problem are either good steam tracing to avoid condensation or selection of a material resistant to the sour condensate corrosion.

Slag Removal

Buggenum: Erosion/corrosion has been experienced in the slag discharge piping. This cost about 120 hours of outage time in 2002. The original piping has now been replaced using duplex steel. Processing of the slag bath water (i.e. separation of the fines from the water) was also an early problem but this was solved by installing a different kind of separator (lamella).

Puertollano: In the areas of solids handling including slag and fly ash erosion of components has been experienced where local velocities are high. Parts have been replaced using abrasion resistant materials. In places design and operating procedures have been revised.

Polk: The slag crusher seal has been a cause of downtime

Wabash: Wabash’s proprietary slag let-down system has not been reported as being a source of problems. Only on one occasion has plugging with slag been reported.

Syngas Cooling

When taking all plants together the syngas cooler is probably the single item requiring most attention. All plants consistently report unplanned outage for maintenance to the syngas cooler. There are essentially two failure modes: Fouling (or plugging) and leakage.

Buggenum: Both fouling and leakage have occurred. Fouling was mostly connected with unannounced changes in coal quality in a similar manner to the slag lump formation discussed above. Improved operation has solved this problem.

Leakages have continued into recent years (350 hours in 2002, 380 hours in 2003). The origin of the leaks lies in vibration and (lack of) flexibility in the tube layout in the cooler.

Puertollano: The Prenflo syngas cooler is divided into two sections. The high pressure, primary cooler is located in the gasifier vessel, while the intermediate pressure cooler is separate. Fouling of the primary cooler is a continuing problem [Garcia Peña, 2005]. The problem of sticky ash is an operational issue, which has been solved by increasing the quench gas flow, so as to reduce the cooler inlet temperature. The other problem of fluffy fly ash is attributable to a too conservative approach to gas velocities in the design.

Polk: In Polk the cooling duty is split between the radiant cooler and the horizontal convection coolers. While downtime due to the former has been relatively limited (288 hrs in 1999, 96 hrs in 2001), the convective syngas coolers (CSCs) have been one of the major problems, requiring no less than 10 stops in the three years 1999 to 2001 totaling nearly 1500 hrs outage (although some of this was masked by other activities). This was almost all connected with fouling and plugging. An important change made on site was to improve accessibility.

The problem with the plugging of the CSC is of sufficient continuing magnitude that GEE have indicated that for their reference plant they will be offering a radiant cooler only solution, largely based on the availability impact created by the convective syngas cooler [Rigdon, 2005].

Wabash: Wabash has had two sources of problem with its vertical convective syngas cooler. Initially there was a certain amount of fouling, which could be attributed to tars in the syngas carried over from the second stage gasifier. This would appear to have been solved by improved operation, though using a petcoke feed would have ameliorated this problem anyway. As part of the activities to overcome the problem a modification was made to the inlet area to improve accessibility.

The other major fouling incident was a loss of 607 hours of production because of sodium contamination of the slurry. Sodium carbonate condenses out on the CSC tubes and inhibits heat transfer and creates excessive pressure drop. Syngas Consultants Ltd is aware of another experience with a problem caused by sodium contamination of feedstock on an oil fed unit where the feed oil arrived by ocean tanker and was contaminated with sea water. In the case of Wabash, the source of the sodium has not been disclosed publicly, but most probably it originated with a recycle of waste water that had been neutralized with caustic soda.

Syngas Piping

Polk: The raw syngas line suffered from erosion and corrosion. The most important problem was the use of 90° elbows in the line (even some short radius elbows). These were preferred locations for erosion damage. This was eliminated by completely rerouting the line to minimize the number of bends and by using 5D bends, where they were absolutely necessary. Note that a similar erosion problem at the 90° elbows in the slurry lines had already been identified in the Cool Water plant, where for these lines a similar solution was adopted.

Syngas Pretreatment

Dry filtration

Buggenum: Initially there were problems with the ceramic filter plugging and having to be replaced at intervals of about 4000 hrs. Further development between the suppliers (Pall Schumacher) and Nuon have increased the lifetime of the filters to over two years, so that exchange can be conducted during the planned outages governed by gas turbine inspection and maintenance program [Scheibner and Wolters, 2002].

Wabash: The Wabash plant was initially equipped with a ceramic candle filter. These suffered from breakage for a number of reasons and were replaced with sinter metal candles in 1996. These have generally proved to be satisfactory, but must be replaced approximately every 8000 hours due to blinding by corrosion.

Puertollano: Puertollano uses ceramic candles, but in contrast to Buggenum continues to experience lifetimes of about 4000 hours. The failure mode is by plugging. Elcogas have an ongoing program to resolve this issue [Lupion, 2005].

Wet Scrubbing

Buggenum: Nuon has reported one incident, when the Syngas Scrubber was corroded when operating at low pH. Automatic pH measurement (and therefore automatic control) has proved to be unreliable. pH control is therefore now based on manual analyses and the problem has been overcome by this means.

Polk: Polk has no particulate filter so that all particulate matter carried over from the radiant cooler must be removed in the scrubber. The “black water” rundown from the scrubber therefore has a high tendency for erosion as well as corrosion.

The scrubber is a limiting factor in the start up procedure. There is a tendency for water to carry over. This water contains chlorides and metals, two critical poisons for the COS hydrolysis catalyst. On one occasion during start up, the carry over reached the COS hydrolysis vessel and the catalyst was damaged causing an 86 hour production loss [McDaniel, 2002]. Operational procedures are in place to prevent this happening again. However this is at the cost of a slower start up with all the associated expense involved (gasifier feed being flared unproductively etc.)

Gas Clean-up and Sulfur Recovery

Acid Gas Removal

Acid gas removal and Claus sulfur recovery units are traditional workhorses in the oil refining and gas industries. They not been a major source of outage in IGCC plants, but nonetheless there have been a number of “lessons learned” specific to this application. Acid gas removal in gasification-based chemical plants has mostly been implemented using the Rectisol process, which uses cold methanol as solvent. This process copes well with the range of trace component in raw syngas and achieves the purities required for the downstream chemical operations (typically < 0.1 ppmv total sulfur). The process is however expensive and this purity is an order of magnitude “deeper” than required for power generation. For this reason alternative, cheaper solutions were applied in the IGCC units, mostly MDEA, but also Selexol and others. Table 5-2 provides an overview of these processes

Table 5-2
Overview of Acid Gas Removal Units in IGCC Plants

Plant	AGR Process
Buggenum	**HCN/COS-Hydrolysis + Sulfinol[7]**
Wabash	**COS-Hydrolysis + MDEA**
Polk	**COS-Hydrolysis + MDEA**
Puertollano	**COS-Hydrolysis + MDEA**
Pernis	**Rectisol**
ISAB	**COS-Hydrolysis + MDEA**
Sarlux	**COS-Hydrolysis + Selexol**
Falconara	**COS-Hydrolysis + Selexol**
Negishi	**HCN/COS-Hydrolysis + ADIP[8]**
Kingsport	**Rectisol**
Coffeyville	**CO-Shift + Selexol**

Performance

The performance of the acid gas removal sections of IGCC units has in general been relatively good although also here, there have been a number of lessons to be learned.

COS hydrolysis: The COS hydrolysis units have overcome their initial difficulties. Typically COS hydrolysis catalysts are sensitive to halides and heavy metals. They are also prone to damage, when operated too close to the dew point.

Polk was not initially equipped with a COS hydrolysis so this had to be retrofitted. In Wabash there was initially no water wash in the pretreatment section, so that halides and metals broke through and damaged the catalyst. The water wash was retrofitted quickly after that. In Puertollano the alumina-based catalyst initially selected had an extremely short lifetime (2 to 3 changes per year) [Puertas Daza and Ray, 2004]. It was later replaced by a more expensive, titania-based catalyst, which successfully operated for four years. At the same time as the new catalyst was introduced, the inlet temperature was raised, thus increasing the approach to the dew point. It is not clear to what extent the improved performance was due to the new catalyst or alternatively to the increased inlet temperature. After several years successful operation the titanium catalyst was damaged by oxidation in August 2005. Then, in January 2006 it experienced a temperature excursion >250ºC during initial warm up. Elcogas replaced it at that time, and again at the end of April. They have decided to switch back to using alumina catalyst which is only 1/8th the cost of the titanium catalyst.

[7] Sulfinol is a proprietary mixture of amines with the physical solvent sulfolane.

[8] ADIP is a process using diisopropanol (DIPA) amine as solvent

Polk has also experienced catalyst damage by carry over from the scrubber during start up. There is now an operating procedure in place to prevent a repeat occurrence, although this does tend to extend the length of the start up time.

Oil feed plants have a guard bed in front of the main COS hydrolysis reactor. The primary purpose of these guard beds it to capture nickel sulfide caused by the decomposition of nickel carbonyl in the superheater. On inquiry at one such plant, assurance was given that there had never been any problem with the COS hydrolysis catalyst. A suitable guard bed could also have protected against some of the incidents mentioned above.

One apparent surprise in all these three plants as well as in Falconara [Sharp, 2002] was the extent of formic acid formation on the COS hydrolysis catalyst with consequences for the downstream amine or Selexol unit. Interestingly the only coal-based plant not reporting problems of this nature is Buggenum, where the hydrolysis unit is declared as an HCN/COS hydrolysis. It is also interesting to note that Negishi has an ammonia wash between the Hydrolysis and Amine Units. Most of the formic acid would be removed with the ammonia.

MDEA: In Polk, Wabash and Puertollano there has initially been excessive degradation of the MDEA caused by the entrainment of formic acid from the COS hydrolysis. This degradation causes the formation of corrosive heat-stable salts (HSS). There were two lost production events of over 100 hours in Polk attributable to this cause and one in Wabash.

These problems have been solved by the introduction of a small ion exchange unit into the solution circuit and need not be expected in future plants.

Sulfinol: Lost production attributable to the Sulfinol unit in Buggenum is very small, the only incident being attributed to operating the regenerator at too high a temperature. The products of the resulting degradation caused the unit to foam, leading to carry over of the Sulfinol solution into the syngas saturator's water system.

Selexol: Selexol plants have generally proved successful. Typical problems arise when unspecified quantities of trace components are contained in the feed gas. In Coffeyville amounts of ammonia larger than expected reacted with CO_2 in the system to form ammonium carbamate which plugged the trays [Barley, 2003]. Formic acid entering the Falconara unit caused localized corrosion damage in the regenerator [Sharp et al, 2002].

Rectisol: Rectisol plants have regularly delivered gas at very low sulfur slip levels (generally 100 ppb, in Beulah 20ppb). In both Beulah and Pernis clogging of the methanol-water column has been recorded as a source of excessive maintenance.

Sulfur Recovery

The Claus plants installed in IGCC units are all typical of the suppliers' designs for refinery application although there are variations in the manner of integration into the overall IGCC. All use oxygen in the Claus furnace which reduces investment costs. The incremental oxygen demand on the ASU is relatively small compared with that for the gasifier. Treatment of the tail gas varies however. Some plants use a traditional tail gas treating (TGT) unit; in which the tail gas is hydrogenated and scrubbed with an amine solution before being incinerated and discharged to atmosphere. Others recycle the tail gas to a point upstream of the acid gas removal. This eliminates a point discharge, and increases the mass flow to the gas turbine. The point at which the recycle ties into the main stream varies from plant to plant.

These features are summarized in Table 5-3. Polk is unusual in that the acid gas is processed to sulfuric acid.

Table 5-3
Claus Units in IGCC Plants

Plant	t/d	O_2/Air	Tail Gas Recycle	Designer
Buggenum	**1x26**	**O_2**	**TGT (SCOT)**	**Jacobs (Comprimo)**
Wabash	**1x120**	**O_2**	**Recycle to gasifier**	**COPE**
Polk	**H_2SO_4**			**Monsanto**
Puertollano	**1x76**	**O_2**	**Recycle to COS Hydrolysis**	**Uhde**
Pernis	**Integrated with refinery Claus plants**			
ISAB	**3x95**	**O_2**	**TGT**	**Lurgi**
Sarlux	**2x188**	**O_2**	**Recycle to Selexol**	**Lurgi**
Falconara	**2x55**	**O_2**	**TGT (MDEA)**	**Parsons**
Negishi	**100**	**O_2**	**TGT (SCOT)**	**Lurgi/Shell**

Performance

There has been very little outage attributed to the Claus units. The only reported incident was a loss of 592 hrs in Buggenum, where an incorrectly designed tubesheet in a heat exchanger leaked and had to be repaired.

Despite the generally good performance of Claus units in IGCC plants, it is necessary to recognize the extremely sensitive task that they have to fulfill. The Claus unit is responsible for achieving the sulfur removal specified in the plant permit. A short outage of the Claus unit will lead to exceeding the total annual permitted sulfur emissions, and so will inevitably trigger a gasifier shutdown. It is for this reason that the refinery units tend to have multiple units, typically 2x 60% and prudent design practice dictates that future commercial IGCCs would adopt a similar philosophy.

Combined Cycle Unit and Balance of Plant

General

Typical availabilities for gas turbines operating on natural gas are in the range of 90-95%. A study based on the extensive ORAP databank has shown that there is significant difference between the "mature" or E class gas turbine designs and the high performance F class designs. [DellaVilla, 2005].

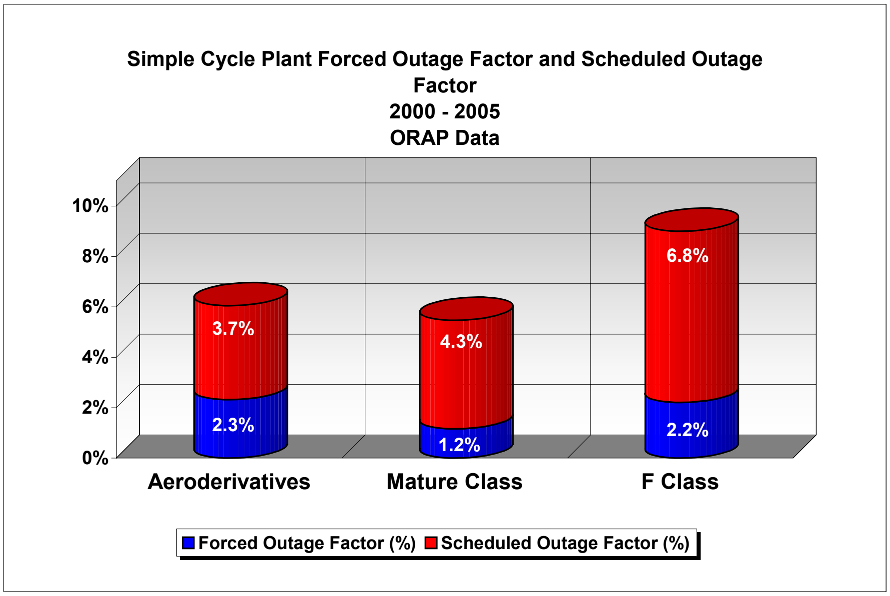

Figure 5-2
Outage Factors for Gas Turbines on Natural Gas

It is important to note how much of this outage time derives from planned outage.

One conclusion to be drawn from these numbers is that it is unrealistic to expect the same availabilities from an IGCC as from a chemical plant where synthesis units can run several years in between catalyst changes.

The results for gas turbines in the four large coal-based IGCC plant do not however come close to these numbers. And when one examines the reasons for outage on these machines in detail, it transpires that with the exception of the very early years in Buggenum, these are unconnected with the use of syngas as fuel.

Table 5-4
Gas Turbine with Syngas as Fuel

Plant (solid feed)	Turbine Model	Plant (liquid feed)	Turbine Model
Buggenum	**Siemens V94.2**	**Pernis**	**GE 2x6B**
Wabash	**GE 7FA**	**Sarlux**	**GE 3x9E**
Polk	**GE 7FA**	**ISAB**	**Siemens 2xV94.2K**
Puertollano	**Siemens V94.3**	**Falconara**	**Alstom 13E2**
SVZ	**GE 6B**	**Singapore**	**GE 2x6FA**
Vresova	**GE 2x9E**	**Negishi**	**Mitsubishi 701F**
El Dorado	**GE 6B**	**Sanazzarro***	**Siemens V94.2K**
Delaware	**GE 2x6FA**		

The record of the CCU performance in the four coal-fired IGCCs are shown in Figure 5-3.

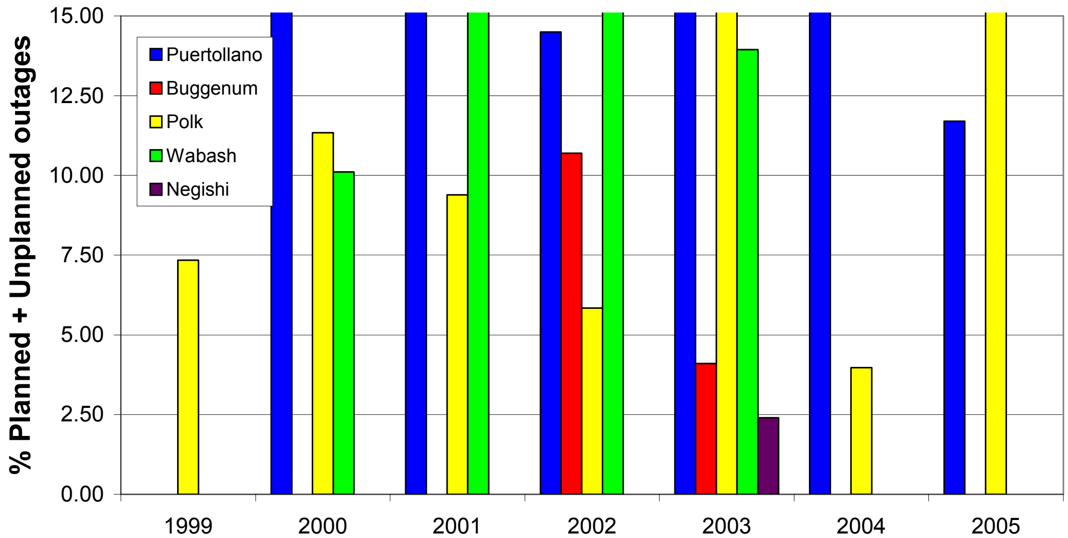

Figure 5-3
Outages attributed to CCU

It should be noted that this data is not complete, since at least planned outages in Buggenum would have to be added. The issues shown in the figure include the following:

Buggenum: 2002 937 hrs, 2003 359 hrs. Non-availability of power block, in neither case attributed to any specific problem [Wolters, 2003]. Assumed mostly planned maintenance.

Wabash: The split ownership of the plant has resulted in less information on the CCU being available than for the syngas production. The data shown includes: a 100-day outage due to a combustion turbine failure in 1999 [Final Technical Report to DOE, 2000] and a 19-day outage in 2000 due to a failure of tubes in the HRSG. The latter were related to expansion issues with the bottom supported unit [Payonk, 2000].

Numerical values for subsequent years are estimated as being 90% of reported hours "product not required". Problems known to have occurred during this period include continued leakages in the HRSG.

In 2004 plant operations were interrupted for business reasons and only resumed mid 2005.

Polk: 2000: 416 hours due to problems with the distillate fuel system.

2003: replacement of the 7FA rotor and rewinding of both generators (24 days of unplanned outage)

2005: 100-day outage due to damaged gas turbine air compressor.

Puertollano: This machine is one of only a handful of V94.3 machines ever built. There have been persistent problems in the horizontal burner silos. Until 2003 a preventative hot gas path inspection was made every 500-1000 hours and the rate of ceramic tile usage in the silo was high. Since a burner modification was made in 2003, the inspection frequency was reduced to every 4000 hours, which is still high compared with an expected 3 year interval.

Particular events include the following:

2001: 617 hours for "three minor inspections to revise & change ceramic shields from combustion chamber and other inspections to change diagonal swirlers" [Mendes Vigo, 2002].

2002: 105 hours "Changing tiles in both gas turbine combustion chambers. Hot temperature in combustion chambers due to misalignment of tiles, unbalance of gas flow and hot spot created during steam injection for NO_x control transients." [Mendes Vigo, 2002].

2003: Deformation of casing flange between compressor and turbo expander. (3 month outage)

2004/2005: Gas turbine transformer bushing fault caused outage (about three months)

2005: DCS problems and compressor inlet guide vane actuator failure

6
SUMMARY AND CONCLUSIONS

Availability of Existing IGCCs

The most complete set of statistics for the availability of the existing coal-based IGCC plants is for the years 2001 to 2003. By the end of this period these plants had been in operation from between six (Puertollano) and nine (Buggenum) years, so that any typical construction and start up issues must be considered to be well and truly overcome. The outage times averaged over the four plants are shown in Figure 6-1. The overall average availability over the three year period is 70%

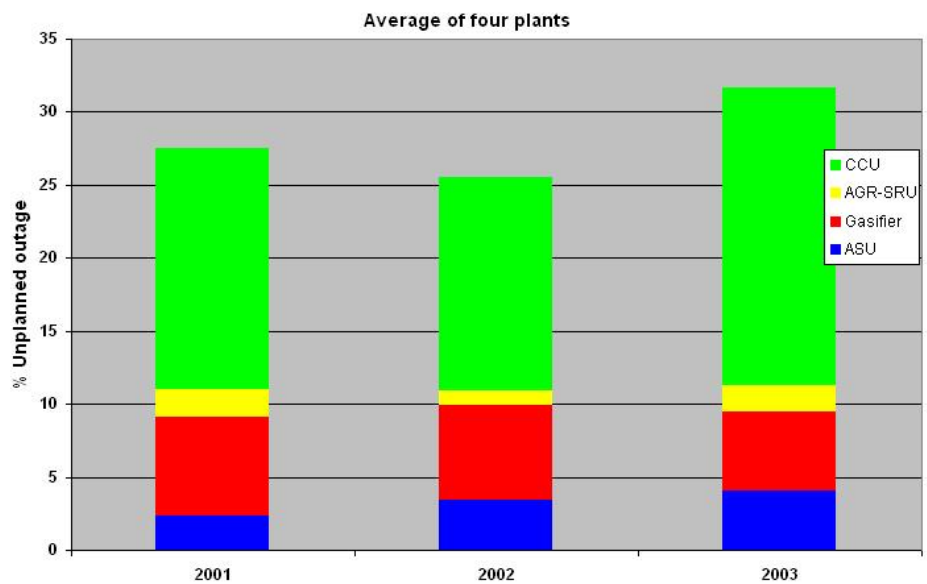

Figure 6-1
Overall outage time by main plant section

This can be contrasted with the availability performance of three Italian refinery based IGCCs, which is portrayed in Figure 6-2. In these cases one can see that availabilities of the order of magnitude of 85 to 95% have been achieved – even if in these cases it has taken two to three years to reach this level.

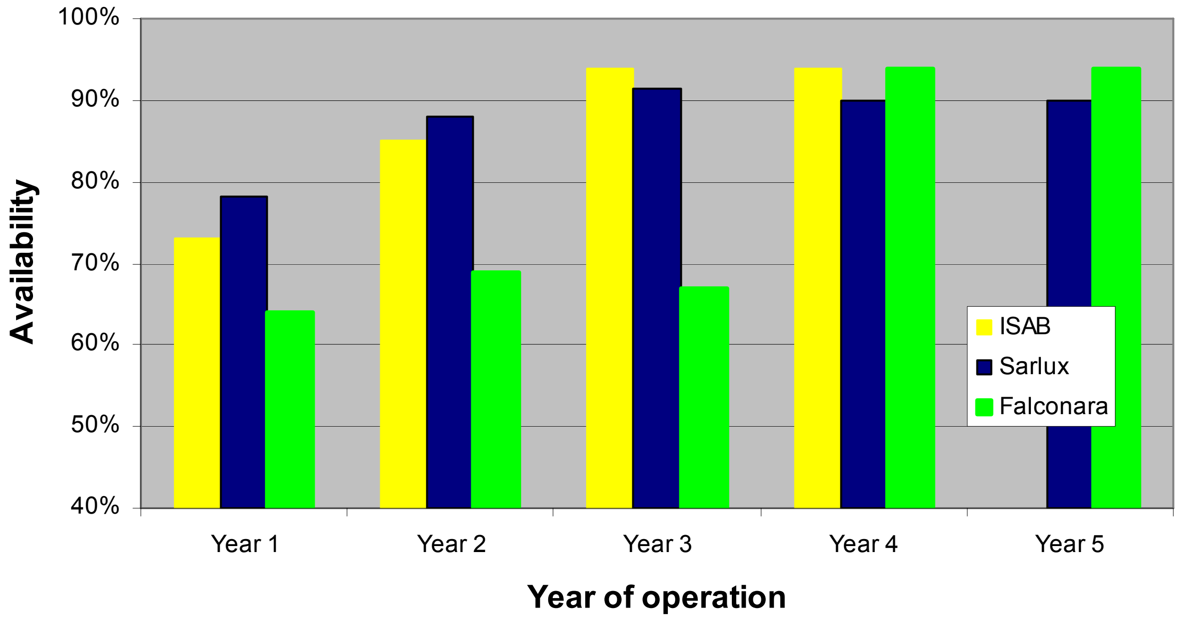

Figure 6-2
Availability Ramp up in Italian Refinery IGCCs

[Sources: Collodi, 2003, Arienti, 2005 and Allevi 2005]

When looking at the performance of the coal-based units, it is striking just how much of the outage time is attributable to those units, where one would not have expected it – ASU and CCU.

From the discussion on page 5-1 ff. it becomes clear how much of the **ASU block** downtime was avoidable – and is avoided in the industrial gas supply industry. In terms of lessons learned, there is little, of which it can be said that it was not known at the time these plants were built and the issues were not technologically connected with the IGCC.

In the **Gasification block** discussed on page 5-5 ff. the situation is somewhat different. While some issues could have been thought about in advance, such as the risk of erosion at elbows in slurry lines, and are in the meantime in the technology suppliers' lists of lessons learned, there are other issues which still have to be overcome. A prime example is the fouling and leaking of high temperature syngas coolers. These issues have affected all technologies to varying degrees and will need to be considered carefully in the O&M strategy of any new plant.

While the **Gas treatment block** (page 5-9 ff.) has not been a major cause of outage, even the 1 to 2% recorded becomes significant when aiming at an overall availability improvement to figures comparable with the refinery-based units. An important lesson learned is the handling of the formic acid issue. The larger outage in 2003 was caused by the tubesheet failure in the Buggenum Claus unit. The adoption of a 2x60% unit approach discussed above can contribute to improved reliability.

The **Combined Cycle Unit** discussed in more detail on page 5-12 ff. is more complicated. Three of these four IGCC plants were equipped with very early machines from the then new 'F-class' gas turbines. Many of the issues have been fleet problems affecting the natural gas fired machines of the same generation in a similar manner.

By contrast the refinery units, although built later, have chosen the less advanced ‘E class’ machines and this has clearly been an important factor in their better availability performance.

Prognosis for New IGCCs

In developing a prognosis for the availability of a new IGCC plant on the basis of the performance of existing plant, one change in methodology will be applied, namely that consideration will be given to planned maintenance. This will however be done in a slightly simplified form.

When developing an availability schedule over the life of a plant, one needs to take account of the fact there will be “shorter” annual planned maintenance outages, the length of which is dictated typically by gas turbine combustor inspections and, if appropriate, minor refractory repairs. There also will be “longer” planned maintenance outages at less frequent intervals where the length of the outage is determined by a GT hot gas path inspection or a full refractory replacement. For the purposes of this report no distinction will be made between these two types of planned maintenance.

In developing a prognosis the following assumptions will be made:

- For the gas turbine it is assumed that an ‘F-class’ machine will be used, which in the meantime has a long term proven tack record in natural gas service. Typically this might be a GE 7FA. ‘E-class’ machines are considered uncompetitive, despite their higher availability. A newer machine such as the GE 7FB will be considered later. Given that (after the initial teething troubles in Buggenum) essentially none of the outage attributable to the CCU in existing IGCCs is related to the firing of syngas, the average availability data from natural gas fired machined will be used. The base case considers a unit without SCR. The introduction of an SCR presents the risk of having to introduce additional interruptions of operation for washing of heat exchanger surfaces in the HRSG.

  The reason for discussing the CCU as the first item is because it is assumed that this will determine the intervals and length of planned maintenance activities. The average data published from the ORAP data base for ‘F-class’ gas turbines in natural gas service is 6.8% (25 days) for planned maintenance and 2.2% (193 hrs) for unplanned outages [DellaVilla, 2005]. These values will be used as averages, noting that there is a performance spread of about 1 percentage point between utilities and non-utilities and more between “best-in-class” and the average. Note however that for ‘E-class’ machines the averages are 4.3% and 1.2% for planned and unplanned outage respectively.
- The typical availability for ASUs in the industrial gas industry – and in other gasification plants – is about 98.5%. Of this 1% can be allocated to routine maintenance, typically de-riming at intervals of say two years. This is adequately masked by the annual planned maintenance for the gas turbine. The remaining 0.5% (44 hrs) must be foreseen as unplanned outage. These values take no credit for the installation of a liquid oxygen storage tank. As noted on page 5-4 this must be reviewed on a project-specific basis.
- For the purposes of this study the assumptions about the gasification section have been chosen conservatively. The outage time over the 2001-2003 period was 6.21%. Since most of the planned outage (typically refractory repair) was masked by the gas turbine

outage, this figure is assumed to be unplanned outage only and thus additive to the planned outage defined above. Clearly the technology suppliers have taken a number of "lessons learned" on board (e.g. eliminating the CSC by GEE [Rigdon, 2005], replacing the refractory lined heat skirt by a cooled wall by Shell [Chhoa, 2005]) in a clear effort to improve availability. On the other hand, it must be recognized that there is a residual risk that not all root causes for unplanned have been identified or alternatively that remedial measures taken may introduce new causes of outage – at least for the first few years. On the other hand there is an advantage in the time lag between the 1990's generation and the next generation of plants, namely that sufficient time has passed, to have a degree of confidence that long-term issues such as corrosion have had sufficient time to reveal themselves.

On this basis the unplanned outage time for the gasification section has been assumed to be about 5.0%. If the combined design team of licensor and EPC together with the owner perform a thorough analysis of all lessons learned on an industry-wide basis, this number could well be reduced further.

- A total plant outage time attributable to the Gas treating section of 0.5% has been foreseen. This assumes that the IGCC-specific lessons are learned (e.g. installation of a guard bed for the COS hydrolysis, the formic acid issue for MDEA units etc.). It conforms with experience of chemical applications of gasification, where the AGR unit essentially runs through from turnaround to turnaround without interruption. It furthermore assumes a 2x60% strategy for the Claus plant. The important issue here is that if there should be a short trip of the Claus plant (attributable typically to an instrumentation fault), the gasifier can continue to operate at reduced load, rather than having to be tripped, which would cost all the loss of production time associated with a re-start.

The above considerations lead to an overall outage time of 15% (availability 85%) as shown in Table 6-1 which is displayed graphically in Figure 6-3.

Table 6-1
Overall Availability Prognosis

	4 plants average 2001-2003	Prognosis (base case)	Prognosis ("E-class availability")
Unplanned outage **ASU**	**3.27%**	**0.5%**	**0.5%**
Gasification	**6.21%**	**5.0%**	**5.0%**
Gas treating	**1.61%**	**0.5%**	**0.5%**
CCU	**17.15%**	**2.2%**	**1.2%**
Total unplanned outage	**28.24%**	**8.2%**	**7.2%**
Planned outage	**incl. above**	**6.8%**	**4.3%**
Available	**71.76%**	**85.0%**	**88.5%**
Total	**100.00%**	**100.0%**	**100.0%**

This table also shows the averaged recorded outage time of the four coal-based operating plants over the 2001 to 2003 time period and a similar consideration based on the availability of 'E-class' gas turbines for comparison. Note that the planned outage for the 'E-class' case is 15 days, which should be sufficient for annual patches in a refractory-lined gasifier. Major refractory replacements would take somewhat longer. A further improvement on the turbine availability would however not necessarily translate into an improvement in overall plant availability because refractory replacement, if required, would become the limiting item on turnaround duration.

Two caveats should be placed on the base case numbers. Firstly, they make no allowance for reduced availability on new, advanced gas turbines. There is insufficient data available to make a judgment as to whether the next generation of gas turbines for syngas application (GE 7FB or Siemens SGT6-5000F) will meet the same availability targets currently shown by the existing 'F-class' fleets. With both machines the step change is certainly less than that of going from the 'E' to the 'F-class' machines. The 5000F has a large track record with natural gas already and the 7FB has a syngas combustion system derived from the proven 7FA design, so no significant drop in availability is anticipated. None the less at this stage it would be prudent to anticipate additional unplanned outage from this source in the first one or two years of operation.

The second source of additional unplanned outage, which can already be predicted, is that washing ammonium bisulfate from heat exchanger surfaces in the HRSG downstream of an SCR DeNOx unit may become necessary. Various models have been developed and published to predict the level of desulfurization required to keep washing down to once per year [e.g. Heaven and DeSousa, 2004], but little hard practical experience is available at the present time. Clearly the presence of an SCR in the HRSG will be taken into consideration when designing the syngas desulfurization, but this cannot guarantee that excessive fouling will not occur. The most appropriate back up strategy is probably to install sufficient instrumentation to monitor both thermal and hydraulic performance of the exchangers concerned and wash the surfaces on an opportunistic basis when the plant is shut down for other reasons. This may result in increased O&M costs, but would probably not impact availability.

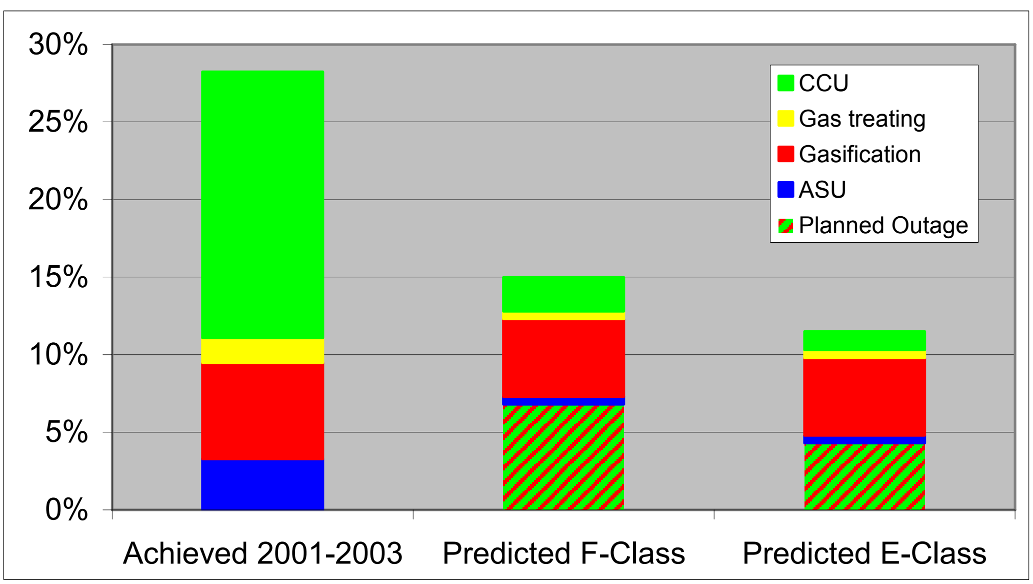

Figure 6-3

Achieved and Predicted Availabilities

Availability ramp up

A further issue to be considered is that with a complex technology such as IGCC, there will be a certain amount of bedding-in time before the long-term availability rates are achieved.

Figure 6-4 shows the actual ramp up of operational availability of a number of coal-based IGCC plants. A visual impression would suggest that the long-term availability figure sets in in about the fourth to fifth year of operation, which contrasts poorly with the oil-based units such as ISAB or Sarlux shown in Figure 6-2, with availabilities close to 90% already in the second year. The experience on chemical product applications of oil gasification confirms the latter data, which is also a reflection of the difference in maturity between oil gasification and coal gasification. It should also be remembered that some of the early difficulties, (e.g. integration issues in Buggenum related to syngas firing of the gas turbine and 100% air-side integration) are now well understood.

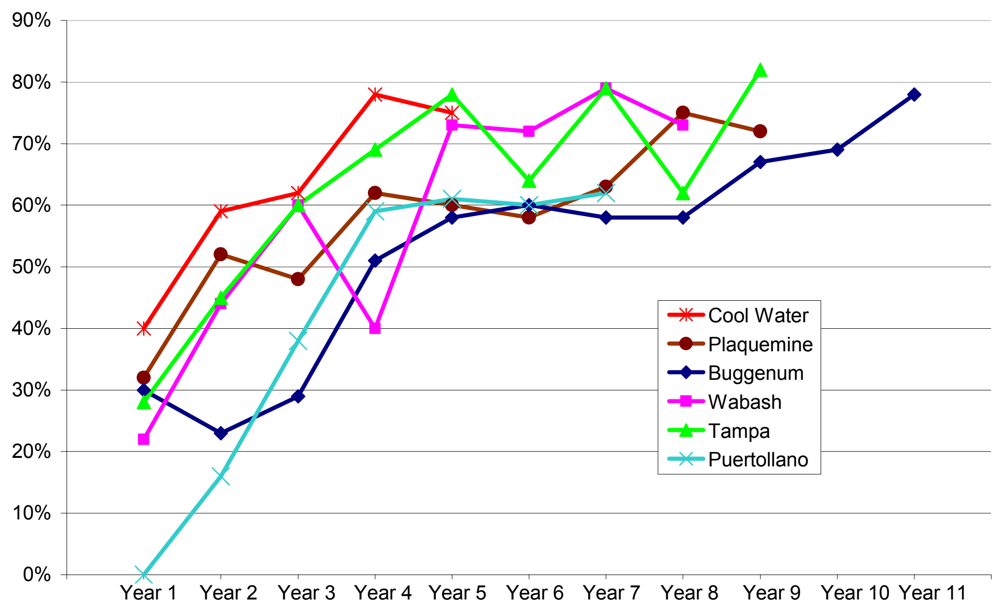

Figure 6-4
Availability Ramp up in Coal-based IGCCs

Based on the consistent application of feedback from the first generation plants into new units, one can anticipate an "oil-type" ramp up for the next generation of coal-based IGCC's. This would suggest the following:

- Year 1 60-65%
- Year 2 75-80%
- Year 3 85%

Note however that in year three the hot gas path inspection of the gas turbine must be planned in. With the 25 day planned outage this should be manageable. If one were aiming at availabilities of 90% (as already achieved with E-class turbines), then the impact of the hot gas path inspection on the third year availability may mean that the 90% figure is only achieved in the fourth year.

Strategies for Implementation

The above discussion on the potential availability for new IGCCs begs a number of important questions, namely

- How can one ensure that lessons learned really are implemented?
- How can one identify changes from existing practice?
- What can be done to minimize risk, where deviations from past practice are identified and agreed? (Such cases can arise from different permitting demands, new solutions to problems identified in the 'lessons learned' process or simply a change of sub-vendor for apparently standard equipment such as valves.)

This report cannot provide a cook book of answers to such questions, but by highlighting them, the intention is to make the potential investor aware that such issues have to be an important element of a project execution strategy, starting already in the preparation phase for Front End Engineering Design (FEED) award.

The following list does not attempt to be exhaustive, but contains a number of typical, representative issues:

- There must be well-defined single point responsibilities with the main EPC contractor. This is true not only for the Project Manger (standard), but also for the Engineering Manager. An IGCC is an integrated plant and this integration requires very careful management at the engineering level.
- Ensure team integration between lead engineers in each major plant block. The interfaces between these blocks will ultimately be managed by the Engineering Manger for the overall plant, but this will only be effective if the communication between the Lead Engineers responsible for the individual blocks is adequate.
- Early involvement of O&M personnel bring these specific skills into the design process and familiarizes the staff concerned with the plant for which they will ultimately be responsible.
- It is necessary to understand early that this is a chemical plant and typical chemical plant techniques must be considered in the design and planning process.
- Introduce safety management concepts at an early stage, both for operations planning and personnel training. This includes Process Safety Management (OSHA 1910.119) and other techniques such as HAZOP. But the schedule and manpower requirements for these programs must be allowed for in the overall project plan.
- Develop a training program early in the project. Training of O&M personnel is essential. This is best done at least partly in an existing plant. Maintenance personnel should receive training for certain critical equipment (e.g. large turbocompressors) in the vendor's works. A process simulator is another useful tool to incorporate in the training program for operations staff.
- Allow sufficient time for process and instrument checking after construction. This activity requires time and effort. It also requires patience and standards should not be relaxed at this point. Involve the plant personnel in the construction checking process. Operations and maintenance personnel will benefit from having seen the inside of equipment, knowing the location of control valves, etc.

- Allow for problems in start up (3 months unprogrammed events). Probably half of this allowance may be hidden in the financial planning, but it is seldom that in a plant of this extent nothing goes wrong. Typical issues experienced in projects of similar magnitudes include a high pressure heat exchanger, where a flange leak (water) damaged the gasket sealing surface and the exchanger had to be sent to an outside workshop for re-machining. In another case, an instrument error caused severe damage to the coils of a fired heater, which had to be repaired. This type of incident is neither fundamental to the process, nor is it predictable (otherwise one could take suitable advance action). It can however quickly cost three weeks of start up time.
- Consider buying oxygen over-the-fence and putting a commercial incentive on high availability.
- Allow float for opening cold box after start and test of ASU. This has been practiced successfully on a number of plants. Historically lead times for ASUs have been typically such that this strategy can be incorporated in the overall schedule.
- Include a sufficient budget for maintenance. In the long term this could work out to an annual budget of 2.5 to 3 % of the capital investment for the gas production section (consider CCU separately). During the first three years it is advisable to foresee considerably more – up to double. Once the availability is up, the maintenance cost will come down by itself.

A
APPENDIX A - LITERATURE REFERENCES

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B

APPENDIX B - LIST OF EVENTS IN PUBLIC DOMAIN

The following is a list of events leading to downtime extracted from various sources quoted in the reference list to this report. Some of these events have been named without any time or duration named. Where such information is not given in the literature, it is left blank below. Others are identifiable by the year in which they occurred. For the Polk plant events up to and including 2001 are identified by the day of their occurrence in the DOE Final Report. Irrespective of whether durations are quoted as hours, days or percentages, these have been reduced to hours off-line so as to facilitate a consistent presentation.

Buggenum

Begin	Duration	Description	Block	Unit
[date]	[hrs]			
		Hydrocarbons build up in ASU (trip)	ASU	Coldbox
		Hydrothermal aging of molecular sieve material	ASU	Mol sieve
		CO2 breakthrough in ASU	ASU	Mol sieve
		General controls in ASU	ASU	
		Leakage - LIN vaporizer (cracks from thermoshock)	ASU	
		Oxygen distribution (Compressor/backup)	ASU	Compr.
		Damaged seal on LIN/LOX pumps	ASU	
		GT trip due to instrument calibration work on ASU	ASU	
		GT burners humming and overheating	CCU	GT
		GT burner overheating	CCU	GT
		Contamination of water with Sulfinol	Clean up	AGR
		Fouling in AGR	Clean up	AGR
		Degradation of Sulfinol	Clean up	AGR
		Bridging in powder coal sluicing vessel	Gasif.	Feed
		Low lifetime of nitrogen injection device	Gasif.	Feed
		Damage to heat skirts	Gasif.	Reactor
		Pressure equalization over membrane wall	Gasif.	Reactor
		Formation of slag lumps	Gasif.	Slag
		Discharge and processing of slag fines	Gasif.	Slag
		Processing of slag bath water	Gasif.	Slag
		Leakage - Slag bath circulation system	Gasif.	Slag
		Slag transport drain stuck	Gasif.	Slag
		Specific areas of erosion in slag system	Gasif.	Slag
		Failure of ceramic candles	Gasif.	Part. Filter
		Leakage - Hot gas filter blowback nozzle (trip)	Gasif.	Part. Filter
		Fly ash transport (plugging)	Gasif.	Part. Filter
		Damage to bag filters due to faulty interlock	Gasif.	Part. Filter
		Fly ash - failure of ceramic filters (life now >8000 hrs, perhaps 16000 hrs	Gasif.	Part. Filter
		Refractory failure below slag tap (replace with membrane wall in new units	Gasif.	Reactor

Buggenum (cont.)

		pH control in syngas scrubber	Gasif.	Scrubber
		Leakage - Caustic line in halogens wash column	Gasif.	Scrubber
		Wet scrubbing corrosion (failure of pH detector)	Gasif.	Scrubber
		Leakages in syngas cooler	Gasif.	Cooling
		Severe fouling of top of syngas cooler	Gasif.	Cooling
		Trip of quench gas blower (Instrumentation)	Gasif.	Cooling
		Production of make up water for steam cycle	BOP	
		Plugging of waste water equipment	BOP	
		Separation and processing of salt crystals	BOP	
		Zero liquid discharge/surplus process water	BOP	
2002	149	Drain ASU blockage	ASU	Coldbox
2002	95	Powdered coal dust filter	Gasif.	Feed
2002	122	Slag bath circulation	Gasif.	Slag
2002	352	Syngas cooler pipes	Gasif.	Cooling
2002	487	Overhaul too late	Misc.	
2002	149	Other forced outage	Misc.	
2003	226	ASU/LOX valves	ASU	
2003	114	DGAN quality trips	ASU	
2003	593	Leakage on Claus tubesheet	Clean up	SRU
2003	381	Syngas cooler pipes	Gasif.	Cooling
2003	68	Other forced outage	Misc.	
01/01/2004	29	CCU triped because of EPA pump trip.	CCU	
17/01/2004	32	Leakage in bend in pulverized coal line	Gasif.	Feed
09/04/2004	16	LIN shortage after trip of CCU and ASU	CCU	
10/04/2004	40	CCU trip	CCU	
21/04/2004	790	Planned turnaround		
25/05/2004	30	CCU trip	CCU	
26/05/2004	23	Leak in EFA10AA005		
27/05/2004	2	Gasifier trip after trip of PC burner	Gasif.	Gasifier
27/05/2004	22	ETD10AA002 stuck fast.		
07/06/2004	705	Gasifier trip on burner leakage	Gasif.	
07/07/2004	21	Trip of CCU and ASU	CCU	
15/07/2004	51	O2 pressure low after trip of CCU and ASU	CCU	
17/07/2004	10	Start on syngas' project	CCU	
18/07/2004	354	Start on syngas' project	CCU	
14/09/2004	185	CO2 breakthrough in ASU	ASU	PPU
04/10/2004	9	Vibrations on quench gas compressor	Gasif.	Cooling
16/10/2004	101	Syngas leak EVA10		
01/01/2005	49	O2 pressure low	ASU	
10/02/2005	922	Planned turnaround		
21/03/2005	51	PC leakage	Gasif.	Feed
24/03/2005	27	High water level in slag bath	Gasif.	Gasifier
15/07/2005	301	High dP at syngas cooler inlet because of deposits	Gasif.	Cooling
03/08/2005	25	Problems in Claus/SCOT area	Clean up	Claus
27/08/2005	50	Defective card on steam turbine controls	CCU	ST
02/09/2005	36	Quench gas compressor trip on high discharge temp	Gasif.	Cooling

Buggenum (cont.)

04/09/2005	38	Oxygen shortage from ASU	ASU	
08/09/2005	420	Planned turnaround		
26/09/2005	30	Testing new GT burners	CCU	
28/09/2005	43	Testing new GT burners	CCU	
01/10/2005	19	Testing new GT burners	CCU	
02/10/2005	8	Testing new GT burners	CCU	
07/10/2005	76	Testing new GT burners	CCU	
11/10/2005	46	Testing new GT burners	CCU	
13/10/2005	23	High level in HP steam drum.	Gasif.	Cooling
14/10/2005	12	Testing new GT burners	CCU	
17/10/2005	348	Testing new GT burners	CCU	
01/11/2005	84	Testing new GT burners	CCU	
05/11/2005	63	Testing new GT burners	CCU	
08/11/2005	294	Testing new GT burners	CCU	
25/11/2005	239	Gasifier trip on "steam system release expired"		
16/12/2005	57	PC leak in bag filter	Gasif.	Feed

Wabash

Begin	Duration	Description	Block	Unit
[date]	[hrs]			
1995		Ash deposits in Syngas cooler	Gasif.	Cooling
1996		GT combustor liners	CCU	GT
1996		HRSG tube leaks	CCU	HRSG
1997		GT syngas purge control	CCU	GT
1997		GT spacers	CCU	GT
1998		ASU instrument related nuisance trips	ASU	Instr.
1998		Pipe routing on GT	CCU	GT
1998		Chlorine and metals on COS Hydrolysis catalyst	Clean up	COS
1998		Ceramic filters	Gasif.	Part. Filter
04/01/1996	5	High differential pressure on main slurry burner	Gasif.	
04/01/1996	1	High differential pressure on main slurry burner	Gasif.	Gasifier
04/01/1996	33	High differential pressure on main slurry burner	Gasif.	Gasifier
06/01/1996	19	Steam turbine warm up vent valve packing failure	CCU	ST
07/01/1996	12	Loss of boiler feedwater to waste heat boiler	CCU	BFW supply
13/01/1996	379	High waste heat boiler differential pressure	Gasif.	Cooling
29/01/1996	4	High vibration trip of the recycle syngas compressor	Gasif.	Cooling
29/01/1996	218	High vibration trip of the recycle syngas compressor	Gasif.	Cooling
08/02/1996	0	Fluctuations in boiler feedwater supply pressure	CCU	BFW supply
08/02/1996	45	Blow-out of char recycle line to first stage reactor	Gasif.	Part. Filter
17/02/1996	2	Pressure transmitter failure on waste heat boiler	Gasif.	Cooling
22/02/1996	457	High waste heat boiler differential pressure	Gasif.	Cooling
13/03/1996	27	Liquid sulfur flow into sulfur storage tank impaired	Clean up	Claus
20/03/1996	102	Loss of boiler feedwater to waste heat boiler	CCU	BFW supply
24/03/1996	5	High dP on primary char filtration system.	Gasif.	Part. Filter
24/03/1996	2	Ineffective back-pulse pressure on primary char filter	Gasif.	Part. Filter

Wabash (cont.)

26/03/1996	30	Sheared linkage on tail gas incinerator valve	Clean up	Claus
27/03/1996	1	Loss of boiler feedwater to waste heat boiler	CCU	BFW supply
27/03/1996	0	Ineffective back-pulse pressure on primary char filter	Gasif.	Part. Filter
27/03/1996	51	Failure of main slurry burner, M-120A.	Gasif.	Gasifier
29/03/1996	8	Failed rupture disk on P-110A	Gasif.	Feed
30/03/1996	1	High dP on primary char filter	Gasif.	Part. Filter
30/03/1996	168	Failure of main slurry burner, M-120A.	Gasif.	Gasifier
06/04/1996	1	Loss of boiler feedwater to waste heat boiler	CCU	BFW supply
07/04/1996	282	Transferred off coal operations due to high sulfur levels in product syngas. Root cause indicated as failure of E-160 tubes	Gasif.	Cooling
20/04/1996	8	Blown Gasket on CT knockout drum	CCU	GT
25/04/1996	619	High waste heat boiler differential pressure.	Gasif.	Cooling
21/05/1996	249	High dP on the secondary dry char filter	Gasif.	Part. Filter
01/06/1996	603	High dP on the secondary dry char filter	Gasif.	Part. Filter
26/06/1996	11	Liquid sulfur flow into sulfur storage tank impaired	Clean up	Claus
27/06/1996	74	High waste heat boiler differential pressure.	Gasif.	Cooling
01/07/1996	8	Solenoid failure on a syngas vent valve at GT	CCU	Instr.
02/07/1996	72	Slurry pump discharge line plugged	Gasif.	Feed
16/07/1996	372	Syngas release caused by failed gasket	Gasif.	Cooling
01/08/1996	440	High dP on the secondary dry char filter	Gasif.	Part. Filter
19/08/1996	151	Recycle syngas compressor trip	Gasif.	Cooling
25/08/1996	58	Recycle syngas compressor trip	Gasif.	Cooling
28/08/1996	783	Tar/char breakthrough into LTHR unit	Gasif.	Part. Filter
03/10/1996	1	Pressure transmitter failure on waste heat boiler	Gasif.	Cooling
09/10/1996	84	Failure of the slag crusher gear box	Gasif.	Gasifier
12/10/1996	2	Recycle syngas compressor on low 1st stage flow	Gasif.	Cooling
13/10/1996	3	Failed stop ratio valve linkage	CCU	GT
17/10/1996	36	GT syngas valve problems	CCU	GT
20/10/1996	1227	Piping failure within the Rx Device Cooling Water System.	Gasif.	Gasifier
12/12/1996	90	Trip of main air compressor due to a 3rd stage guide vane malfunction	ASU	Air Compr
17/12/1996	2	False "High Oxygen" indications from Analyzer	Gasif.	
20/12/1996	7	Plugged overflow line on slag hopper	Gasif.	Gasifier
20/12/1996	2	Freezing of HP steam flow transmitter to HRSG	Gasif.	Cooling
21/12/1996	3	False "High Oxygen" indications from Analyzer	Gasif.	
25/12/1996	27	High level in primary dry char filtration vessel	Gasif.	Part. Filter
30/12/1996	6	GT trip while trouble shooting syngas leak	CCU	GT
02/01/1997	69	Cleanout of ash deposits in waste heat boiler	Gasif.	Cooling
05/01/1997	49	High differential pressures within waste heat boiler	Gasif.	Cooling
10/01/1997	3	Frozen BFW pressure transmitter	CCU	BFW supply
10/01/1997	4	Frozen BFW pressure transmitter	CCU	BFW supply
12/01/1997	38	Failed hein joint on syngas feed valve to GT	CCU	GT
14/01/1997	436	High dP across the back-up char filters	Gasif.	Part. Filter
01/02/1997	260	Gasifier taphole plugged	Gasif.	Gasifier
19/02/1997	4	Loss of boiler feedwater to waste heat boiler	CCU	BFW supply

Wabash (cont.)

20/02/1997	6	Loss of boiler feedwater to waste heat boiler	CCU	BFW supply
06/03/1997	2	Failure of slag crusher gear fluid coupling	Gasif.	Gasifier
06/03/1997	0	Loss of boiler feedwater to waste heat boiler	CCU	BFW supply
07/03/1997	14	Leak-by on a syngas feed control valve to the GT	CCU	GT
07/03/1997	163	Flange leak and small syngas fire at Waste Heat Boiler outlet spool piece.	Gasif.	Cooling
22/03/1997	165	Make-up BFW line failure to Rx Device CW System	CCU	BFW supply
29/03/1997	4	Loss of boiler feedwater to waste heat boiler	CCU	BFW supply
08/04/1997	45	Electrical fuse failure on air compressor	ASU	
11/04/1997	781	Electrical fuse failure on O2 compressor	ASU	
13/05/1997	23	GT NOx steam injection valve problems	CCU	GT
15/05/1997	5	GT NOx steam injection valve problems	CCU	GT
19/05/1997	3	Failure of dP transmitter tube failure		
27/05/1997	32	Failure of CT Frame Blower	CCU	GT
29/05/1997	72	Main slurry feed flow instability induced by P-110A/B	Gasif.	Feed
01/06/1997	241	Gasifier taphole plugged	Gasif.	Gasifier
18/06/1997	11	Solenoid valave failure on GT syngas feed valves	CCU	GT
22/06/1997	497	High dP in chloride scrubbing system packing	Gasif.	Cooling
13/07/1997	12	Syngas leak on the extraction gas flow meter		
18/07/1997	52	Main slurry feed flow instability induced by P-110A/B	Gasif.	Feed
04/08/1997	5	Loose fuse in ASU caused oxygen vent valves to open.	ASU	
11/08/1997	13	High sulfur levels in product syngas. Absorber tray damage and faulty product gas analyzer contributed	Clean up	MDEA
26/08/1997	441	High boiler dP and high boiler outlet temperature	Gasif.	Cooling
13/09/1997	1	Slurry magmeters error	Gasif.	Feed
28/09/1997	2	Loss of boiler feedwater to waste heat boiler	CCU	BFW supply
07/10/1997	111	High dp in Absorber as a result of salt build up	Clean up	MDEA
12/10/1997	551	Failed M-120A slurry mixer.	Gasif.	Gasifier
05/11/1997	25	Oxygen syngas leak on DO-119.	Gasif.	Cooling
09/11/1997	40	Slag grinder misalignment	Gasif.	Gasifier
10/11/1997	38	Syngas leak on the inlet flange of the chloride scrubber	Gasif.	Cooling
12/11/1997	50	Failed PSV on C-180 venting acid gas to the flare	Clean up	MDEA
21/11/1997	14	Unable to re-light combustion turbine after slurry mixer upset	CCU	GT
22/11/1997	9	High level in the dry char vessel	Gasif.	Part. Filter
26/11/1997	3	High level in the dry char vessel	Gasif.	Part. Filter
26/11/1997	9	High level in the dry char vessel	Gasif.	Part. Filter
28/11/1997	512	Plugged overflow line from slag hopper	Gasif.	Gasifier
20/12/1997	9	Syngas leak on dry char secondary filter	Gasif.	Part. Filter
30/12/1997	51	Failed decant filter in T-140C	Gasif.	Cooling
03/01/1998	39	Failed slurry mixer M-120B	Gasif.	Gasifier
05/01/1998	5	Blown fuse on O2 vent valve in ASU	ASU	
08/01/1998	32	Failed slurry mixer M-120A	Gasif.	Gasifier
10/01/1998	8	GT main syngas stop/ratio valve leaking	CCU	GT
11/01/1998	161	Malfunction of main air compressor surge valve	ASU	
25/01/1998	87	Malfunction of main air compressor guide vanes	ASU	

Wabash (cont.)

28/01/1998	1	Slurry magmeter drifting low caused high O2/C ratio	Gasif.	Feed
04/02/1998	26	Failed slurry mixer M-120B	Gasif.	Gasifier
05/02/1998	32	15KV power interruption with loss of main air compressor	External	Electrical
13/02/1998	372	First quarter 1998 scheduled maintenance	Planned	
02/03/1998	3	Shutdown of the recycle syngas compressor on false knock out drum level indication		
05/03/1998	36	Failed slurry mixer M-120A	Gasif.	Gasifier
27/03/1998	1	Tripped gasifier on low boiler drum level	CCU	BFW supply
27/03/1998	6	Problems with the GT stop ratio valves.	CCU	GT
02/04/1998	19	Scheduled replacement of slurry mixers	Gasif.	Gasifier
11/04/1998	16	Loss of slurry flow from P-102	Gasif.	Feed
13/04/1998	8	GT trip caused by exciter breaker	CCU	GT
28/04/1998	51	Scheduled inspection of dry char ejectors	Planned	
21/05/1998	469	Char break through in V-155A	Gasif.	Part. Filter
10/06/1998	8	High sulfur in product syngas during activation of new hydrogenation catalyst	Gasif.	Cooling
17/06/1998	60	Oil leak on inboard bearing of oxygen compressor	ASU	
19/06/1998	2	Blown rupture disk on slurry pumps	Gasif.	Feed
27/06/1998	547	Gasifier taphole plugged.	Gasif.	Gasifier
28/07/1998	3	Change out dry char recycle ejector	Gasif.	Part. Filter
30/07/1998	3	False temperature on a syngas exchanger momentarily closed valves in the main syngas path		
04/08/1998	112	Electrical failure on O2 compressor	ASU	O2 Compr.
09/08/1998	116	Failed power supply to the main air compressor guide vanes	ASU	
15/08/1998	42	Blown fuse on the 15KV potential transformer tripped both the oxygen and the main air compressors in the ASU	ASU	Electrical
28/08/1998	4	Change out dry char recycle ejector	Gasif.	Part. Filter
28/08/1998	6	Failed dry char backpulse valve	Gasif.	Part. Filter
31/08/1998	7	Sour water leak on the outlet of the chloride scrubbing column	Gasif.	Cooling
05/09/1998	389	Thrid quarter scheduled maintenance	Planned	
22/09/1998	23	Syngas leak on the dry char vessel inlet flange	Gasif.	Part. Filter
08/10/1998	42	Power switch to the vibration protection equipment main air compressor was accidentally turned off	ASU	Air Compr
10/10/1998	12	Repair of the main water line coming to the CT/ST	CCU	GT
27/10/1998	20	Failed regeneration of ASU molesieve	ASU	PPU
11/11/1998	22	Loss of boiler feedwater to waste heat boiler	CCU	BFW supply
16/11/1998	2	Suction of the slurry stuffing pumps plugged	Gasif.	Feed
04/12/1998	796	Fourth quarter scheduled maintenance outage	Planned	
07/01/1999	11	Slag grinder problems	Gasif.	Gasifier
08/01/1999	55	Syngas leak in one of the LT Heat Exchangers	Gasif.	Cooling
24/01/1999	308	Plugged taphole	Gasif.	Gasifier
07/02/1999	5	Piston failure on the main slurry pump	Gasif.	Feed
25/02/1999	67	High differential pressure across the sour water carbon filters	BOP	SWS
28/02/1999	276	Failed ceramic test filter in the primary dry char system	Gasif.	Part. Filter
13/03/1999	2409	Failed combustion turbine	CCU	GT
23/06/1999	8	Loss of slurry flow from a plugged pump suction line	Gasif.	Feed
04/07/1999	19	Turbine trip caused by a blown fuse	CCU	GT

Wabash (cont.)

05/07/1999	4	GT syngas stop ratio valves not operating	CCU	GT
12/07/1999	2	Slurry feed pump lost suction flow	Gasif.	Feed
13/07/1999	6	Faulty air demand analyzer reading in SRU	Clean up	SRU
16/07/1999	14	Valve problem associated with the absorber bed in the ASU	ASU	
18/07/1999	24	Faulty I/O cards in GT control system.	CCU	GT
21/07/1999	425	Tube leak in the HRSG	CCU	ST
10/08/1999	62	Slag grinder seal leak	Gasif.	Gasifier
06/10/1999	72	Failed slurry mixer	Gasif.	Gasifier
09/10/1999	37	Failed slurry valve	Gasif.	Feed
10/10/1999	13	Leak on a slurry flow meter	Gasif.	Feed
13/10/1999	18	Failed slurry valves	Gasif.	Feed
22/10/1999	717	Scheduled fall outage	Planned	
22/11/1999	502	Syngas leak from the dry char return line	Gasif.	Part. Filter
14/12/1999	5	Loss of slurry flow from plugged pump suction	Gasif.	Feed
27/12/1999	49	Packing leak on slag crusher	Gasif.	Gasifier
1999	312	ASU weld failures	ASU	Coldbox
1999	2352	GT air compressor	CCU	GT
1999		HSS in MDEA	Clean up	AGR
1999		Candle filters	Gasif.	Part. Filter
2000		Oxygen compressor motor grounding	ASU	Compr.
2000		MAC inlet guide vane upgraded	ASU	Compr.
2000	456	HRSG tube failures	CCU	HRSG
2001	298	AG Cooler tube leak	Clean up	AGR
2001	35	Slurry mixer replacement	Gasif.	Slurry
2001	63	Slurry flow interruption	Gasif.	Slurry
2001	11	False filter pressure indication	Gasif.	Instr.
2001	510	Syngas cooler leaks	Gasif.	Cooling
2001	10	Other	Misc.	
2002		MAC Faulty vibration monitor	ASU	Compr.
2002		Low LIN level	ASU	Coldbox
2002		Eratic slurry pump flow	Gasif.	Slurry
2002		Slag quench plugged	Gasif.	slag
2002		Syngas cooler	Gasif.	Cooling
2002		Cracked instrument nozzle	Misc.	Instr.
2003		ASU cracked header	ASU	Coldbox
2003		SRU	Clean up	SRU
2003		Slurry mixer	Gasif.	Slurry
2003		Feed supply interruption	Gasif.	Feed
2003		Overfilled slag hopper	Gasif.	Slag
2003		Refractory breach	Gasif.	Reactor
2003		Sodium carbonate	Gasif.	Cooling
2003		Syngas cooler	Gasif.	Cooling
2003		Other	Misc.	

Polk

Begin	Duration	Description	Block	Unit
[date]	[hrs]			
05/01/99	48	MAC IGV positioner	ASU	Compr.
16/01/99	96	Clean CSC	Gasif.	Cooling
21/01/99	72	RSC sump pluggage – fuel	Gasif.	Cooling
15/02/99	96	Gas leak, elbow by aspirator	Gasif.	Piping
14/03/99	96	Clean CSC, test burner #1	Gasif.	Cooling
26/03/99	216	Clean CSC, Test burner #2	Gasif.	Cooling
10/04/99	48	RSC sump pluggage – fuel	Gasif.	Cooling
17/04/99	72	RSC sump pluggage – fuel	Gasif.	Coal quality
23/04/99	408	Planned outage, CSC modifications	Gasif.	Cooling
18/05/99	72	RSC sump pluggage – fuel	Gasif.	Cooling
22/05/99	96	RSC sump pluggage – fuel	Gasif.	Cooling
26/05/99	576	Planned outage, CT combustor insp. Gasifier vertical hot face refr..	CCU	GT
21/07/99	72	Clean CSC	Gasif.	Cooling
24/07/99	72	Slag crusher seal	Gasif.	Slag
11/08/99	24	SGC MP drum level, Slag crusher seal	Gasif.	Slag
20/08/99	192	COS tie in, Clean CSC, Replace slag crusher seal	Gasif.	Cooling
04/10/99	168	Cooling water leak to MDEA, clean CSC, CT start failure	Gasif.	Cooling
05/11/99	24	Burner leak, CT restart failure	CCU	GT
12/12/99	168	Planned CT stack test, clean CSC	CCU	GT
31/01/00	72	Clean CSCs	Gasif.	Cooling
04/02/00	24	Rebuild Geho	Gasif.	Slurry
09/02/00	48	ST main breaker ground	CCU	ST
26/02/00	432	Planned outage, CT HG Path, Gasifier throat refractory	CCU	GT
17/03/00	408	ASU cold box leak	ASU	Coldbox
07/04/00	192	Atomizing Air Compressor (GT)	CCU	GT
27/06/00	120	CSCs, Geho, MAC coolers	Gasif.	Cooling
29/08/00	120	CT restart failure, fuel fire	CCU	GT
29/09/00	24	DECAN suction vent	ASU	
24/10/00	48	Nozzle leak scrubber	Gasif.	Scrubber
03/12/00	120	MDEA HSS	Clean up	MDEA
08/01/01	48	MAC discharge vent I/P	ASU	Compr.
26/01/01	96	RSC lower seal	Gasif.	Cooling
27/02/01	120	CSC plugging/tube leak	Gasif.	Cooling
17/03/01	720	Planned outage, CT combustor insp. Gasifier vertical hot face refractory	CCU	GT
23/05/01	792	RSC Exit plug Soot blower, MAC 4th stage impeller	ASU	Compr.
09/07/01	48	MAC discharge vent valve solenoid	ASU	Compr.
31/07/01	144	COS Catalyst plugging	Clean up	COS
28/08/01	72	Scrubber B pigtail leak, O2 vent valve	Gasif.	Scrubber
19/09/01	432	Slag disposal, soot-blower removal	Gasif.	Slag
20/10/01	24	LH recirculation line fitting failure		
31/10/01	24	Nozzle Scrubber A barrel check	Gasif.	Scrubber
05/11/01	120	CSC plugging	Gasif.	Cooling
13/11/01	192	Failed elbow, syngas to scrubber	Gasif.	Piping
05/12/01	48	unknown		
14/12/01	24	unknown		

Polk (cont.)

2002	282	Sulfur Removal	Clean up	AGR
2002	86	COS Hydrolysis	Clean up	COS
2002	285	Raw gas piping	Gasif.	Piping
2002	10	Black water piping	Gasif.	Piping
2002	244	Slurry Feed Pump	Gasif.	Slurry
2002	77	Slurry Feed Pump	Gasif.	Slurry
2002	13	Gasifier burner	Gasif.	Burner
2002	85	Miscellaneous	Misc.	
2003	113	MAC 4th stage bearing	ASU	Compr.
2003		Power block inspection	CCU	GT
2003	576	GT Rotor	CCU	GT
2003	240	GT rotor replacement	CCU	GT
2003	178	Black water	Gasif.	Piping
2003	166	Raw gas piping	Gasif.	Piping
2003	43	Slurry system	Gasif.	Slurry
2003		Gasifier refractory	Gasif.	Reactor
2003	216	Convective syngas cooler	Gasif.	Cooling
2003	91	Nozzle failure radiant syngas cooler sump	Gasif.	Cooling
2003	168	Saturator tie-in	Misc.	
2003	34	Miscellaneous	Misc.	
2003	1008	Planned shutdown	Misc.	

Puertollano

Begin	Duration	Description	Block	Unit
[date]	[hrs]			
		WN2 flap problems	ASU	Compr.
	72	GT Cooling air partition	CCU	GT
		Damaged GT Burners/Tiles	CCU	GT
	1008	GT Inner casing overhaul	CCU	GT
		Gasifier plugged	Gasif.	Slag
2001	617	GT	CCU	GT
2001	263	COS Hydrolysis	Clean up	COS
2001	473	Gasifier	Gasif.	Reactor
2001	289	Candle filters	Gasif.	Part. Filter
2001	193	IP Waste heat boiler	Gasif.	Cooling
2002	88	ASU extraction air cooler	ASU	
2002	105	GT burner chamber	CCU	GT
2002	184	Gasifier	Gasif.	Reactor
2002	666	Slag extraction	Gasif.	Slag

Coffeyville

Begin	Duration	Description	Block	Unit
[date]	[hrs]			
		ASU	ASU	
		Flooding in Selexol Absorber	Clean up	AGR
		Corrosion in urea plant	Clean up	AGR
		Carry over from Quench chambers and or carbon scrubbers	Gasif.	Cooling
		Refrigeration compressor motor overheating	Synth.,	

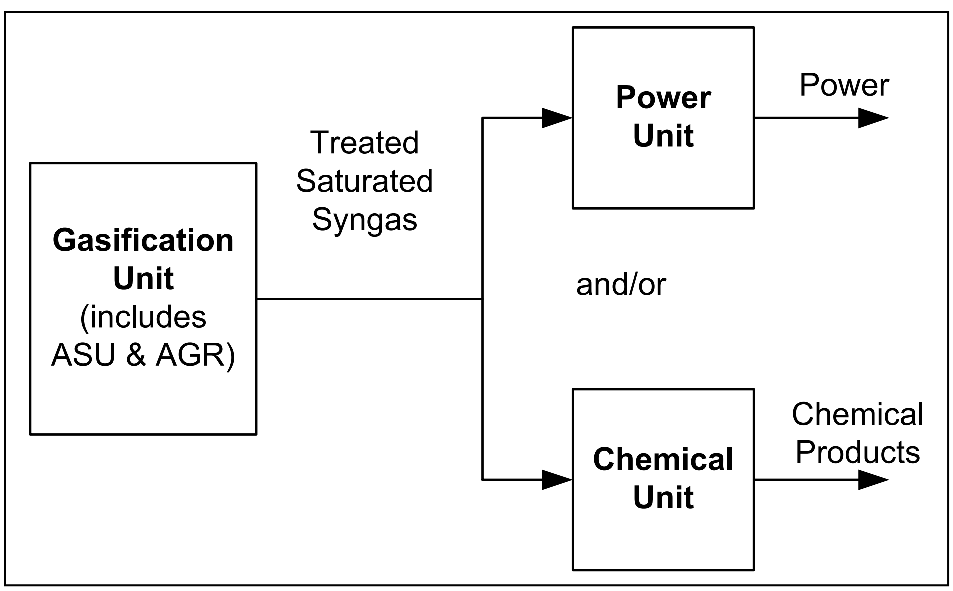
C

APPENDIX C - GUIDELINES FOR REPORTING OPERATING STATISTICS FOR GASIFICATION FACILITIES

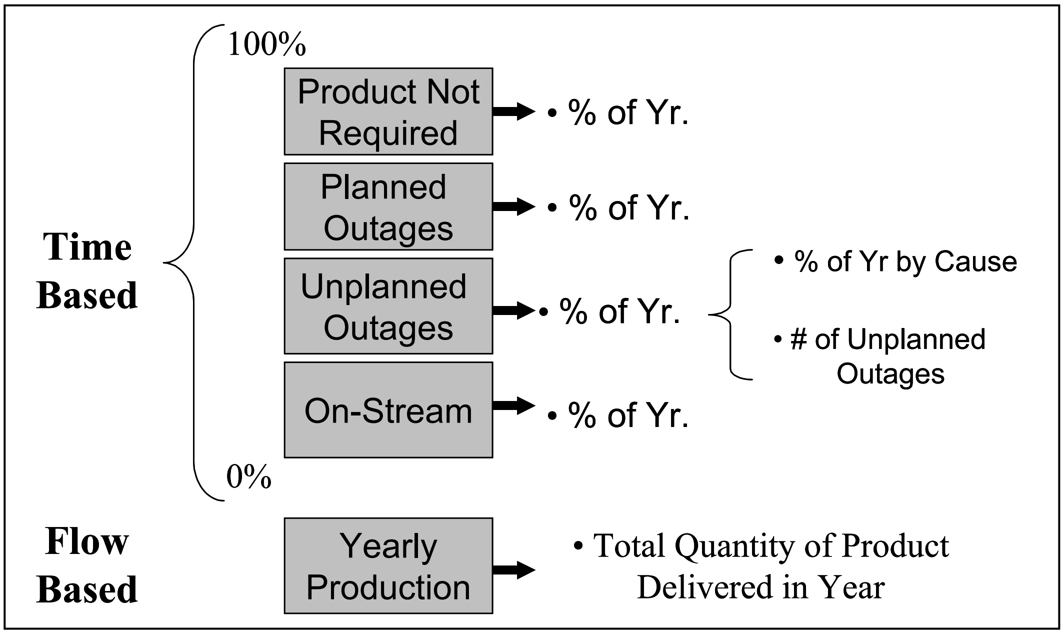
(Courtesy of the Gasification Technologies Council, Rev. 5 February 2002)

- The objective of these guidelines is to present a standardized way for reporting the operating statistics of gasification facilities. The statistics are primarily time-based, however, a single flow-based indicator is also included. An example is included.
- The gasification facility is divided into two units so that the operating statistics can be reported for each of these critical areas of the facility. The units are defined as follows:
    - Gasification (including ASU and Acid Gas Removal Unit)
    - Product Units
        - Power production block, and / or
        - Chemical production block
- Authors are also asked to indicate the specific configurations of the units with regard to back-up and multiple trains.

Gasification Facility Units



Unit Operating Statistics - Measured



Definitions – Measured Statistics

- **Product Not Required**

  % of year that the product from the unit was not required, and therefore, the unit was not operated. The unit was generally available to run and not in a planned outage or forced outage.

- **Planned Outages**

  % of the year that the unit is not operated due to outages which were scheduled at least one month in advance. Includes yearly planned outages as well as maintenance outages with more than one month notice.

- **Unplanned Outages**

  % of the year the unit was not operated due to forced outages which had less than one month notice. Includes immediate outages as well as maintenance outages with less than one month notice.

- **On-Stream**

  % of the year the unit was operating and supplying product in a quantity useful to the downstream unit or customer.

- **Yearly Production**

  Defined as the total quantity of product actually delivered from the unit in a calendar year. For the gasification unit the production is reported on the basis of total clean synthesis gas.

Unit Operating Statistics - Calculated

Time Based	**Forced Outage Rate** = Unplanned / [On-Stream + Unplanned] **Availability** = On-Stream + Product Not Required * [1 – (Forced Outage Rate / 100%)]
Flow Based	**Annual Loading Factor** = Yearly Production / Rated Capacity

Definitions – Calculated Statistics

- **<u>Forced Outage Rate</u>**

  Defined as the time during which the down-stream unit or customer did not receive product due to unplanned problems divided by the time during which they expected product, expressed as a percentage.

- **<u>Availability</u>**

  Defined as the sum of the time during which the unit was on-stream plus an estimate of the time the unit could have run when product was not required, expressed as a percentage of the year. Assumption is that unit could have operated at the same Forced Outage Rate when product was not required.

- **<u>Annual Loading Factor</u>**

  Defined as the yearly production of the unit divided by the rated capacity, expressed as a percentage.

- **<u>Rated Capacity</u>**

  Defined as the design quantity that the unit would produce at the design rate over the calendar year when operated in an integrated manner. Calculated by multiplying 365 times the average annual daily design rate. Note that the Design Production can change over time as the plant is de-bottlenecked or re-rated.

Example

- **Operating Unit is a gasification train which is designed to make 200 mmscfd of syngas**
- **Measured Unit Operating Statistics for this Example:**

  Product Not Required = 10% of year

  Planned Outages = 8 % of year

  Unplanned Outages = 4% of year

  Breakdown of the 4% by Cause

  Report # of interruptions

  Onstream = 78% of year

  Yearly production = 55,000 mmscf of syngas
- **Resulting Calculated Unit Operating Statistics:**

  Forced Outage Rate = 4% / [78% + 4%] = 4.9%

  Availability = 78% + 10% * [1 – (4.9% /100%)] = 78% + 9. 5% = 87.5%

  Rated Capacity = 365 d * 200 mmscfd = 73,000 mmscf

  Annual Loading Factor = 55,000 mmscf / 73,000 mmscf = 75.3%

D

APPENDIX D - IEEE 762 RELIABILITY / AVAILABILITY INDICES AND EQUATIONS

This Appendix discusses the relationships among the performance indexes calculated from the event and performance data outlined in Chapters 2 and 3. The basis for these relationships is IEEE Standard No. 762 "Definitions for Use in Reporting Electric Generating Unit Reliability, Availability and Productivity."

Summary of Various Time and Energy Factors Used by Indexes

1.	Service Hours - SH	Sum of all Unit Service Hours.
2.	Available Hours - AH	Sum of all Service Hours (SH) + Reserve Shutdown Hours (RSH) + Pumping Hours + Synchronous Condensing Hours.
3.	Planned Outage Hours - POH	Sum of all hours experienced during Planned Outages (PO) + Scheduled Outage Extensions (SE) of any Planned Outages (PO).
4.	Unplanned Outage Hours - UOH	Sum of all hours experienced during Unplanned (Forced) Outages (U1, U2, U3) + Startup Failures (SF) + Maintenance Outages (MO) + Scheduled Outage Extensions (SE) of any Maintenance Outages (MO).
5.	Unplanned (Forced) Outage Hours - FOH	Sum of all hours experienced during Unplanned (Forced) Outages (U1, U2, U3) + Startup Failures (SF).
6.	Maintenance Outage Hours - MOH	Sum of all hours experienced during Maintenance Outages (MO) + Scheduled Outage Extensions (SE) of any Maintenance Outages (MO).
7.	Unavailable Hours - UH	Sum of all Planned Outage Hours (POH) + Unplanned (Forced) Outage Hours (FOH) + Maintenance Outage Hours (MOH).

8.	Scheduled Outage Hours - SOH	Sum of all hours experienced during Planned Outages (PO) **+** Maintenance Outages (MO) **+** Scheduled Outage Extensions (SE) of any Maintenance Outages (MO) and Planned Outages (PO).
9.	Period Hours - PH	Number of hours in the period being reported that the unit was in the active state.
10.	Equivalent Seasonal Derated Hours - ESEDH	Net Maximum Capacity (NMC) Net Dependable Capacity (NDC) **x** Available Hours (AH) **/** Net Maximum Capacity (NMC). $\frac{(\text{NMC} - \text{NDC}) \times \text{AH}}{\text{NMC}}$
11a.	Equivalent Unplanned (Forced) Derated Hours – EFDH	Each individual Unplanned (Forced) Derating (D1, D2, D3) is transformed into equivalent full outage hour(s). This is calculated by multiplying the actual duration of the derating (hours) by the size of the reduction (MW) and dividing by the Net Maximum Capacity (NMC). These equivalent hour(s) are then summed. $\frac{\text{Derating Hours} \times \text{Size of Reduction}}{\text{NMC}}$* NOTE: Includes Unplanned (Forced) Deratings (D1, D2, D3) during Reserve Shutdowns (RS). See 11d, Page F-3.
11b.	Equivalent Planned Derated Hours - EPDH (PD, DE)	Each individual Planned Derating (PD, DE) is transformed into equivalent full outage hour(s). This is calculated by multiplying the actual duration of the derating (hours) by the size of reduction (MW) and dividing by the Net Maximum Capacity (NMC). These equivalent hour(s) are then summed. $\frac{\text{Derating Hours} \times \text{Size of Reduction}}{\text{NMC}}$* NOTE: Includes Planned Deratings (PD) during Reserve Shutdowns (RS). See 11d, Page F-3.

* Size of Reduction is determined by subtracting the Net Available Capacity (NAC) from the Net Dependable Capacity (NDC). In cases of multiple deratings, the Size of Reduction of each derating will be determined by the difference in the Net Available Capacity of the unit prior to the derating and the reported Net Available Capacity as a result of the derating

11c.	Equivalent Unplanned Derated Hours - EUDH (D1, D2, D3, D4, DE)	Each individual Unplanned Derating (D1, D2, D3, D4, DE) is transformed into equivalent full outage hour(s). This is calculated by multiplying the actual duration of the derating (hours) by the size of reduction (MW) and dividing by the Net Maximum Capacity (NMC). These equivalent hour(s) are then summed. $\dfrac{\text{Derating Hours } \mathbf{x} \text{ Size of Reduction*}}{\text{NMC}}$ NOTE: Incudes Unplanned Deratings (D1, D2, D3, D4, DE) during Reserve Shutdowns (RS). See 11d below.
11d.	Equivalent Unplanned (Forced) Derated Hours During Reserve Shutdowns - EFDHRS (D1, D2, D3)	Each individual Unplanned (Forced) Derating (D1, D2, D3) or the portion of any Unplanned (Forced) derating which occurred during a Reserve Shutdown (RS) is transformed into equivalent full outage hour(s). This is calculated by multiplying the actual duration of the derating (hours) by the size of the reduction (MW) and dividing by the Net Maximum Capacity (NMC). These equivalent hour(s) are then summed. $\dfrac{\text{Derating Hours } \mathbf{x} \text{ Size of Reduction*}}{\text{NMC}}$
12.	Number of Planned Outages (PO) which occur from in-service state only	A count of the number of all Planned Outages (PO) reported on the GADS Event Report (97). (Since Scheduled Outage Extensions (SE) of Planned Outages are considered part of the original Planned Outage (PO), they are not included in this count.)
13.	Number of Unplanned Outages (MO, U1, U2, U3) which occur from in-service	A count of the number of all Unplanned Outages (U1, U2, U3, MO) reported on the GADS Event Report (97).

state only	(IEEE Standard 762 does not include Startup Failures (SF) in this count.)

* Size of Reduction is determined by subtracting the Net Available Capacity (NAC) from the Net Dependable Capacity (NDC). In cases of multiple deratings, the Size of Reduction of each derating will be determined by the difference in the Net Available Capacity of the unit prior to the derating and the reported Net Available Capacity as a result of the derating.

14.	Number of Unplanned (Forced) Outages (U1, U2, U3) which occur from in-service state only	A count of the number of all Unplanned (Forced) Outages (U1, U2, U3) reported on the GADS Event Report (97). (IEEE Standard 762 does not include Startup Failures (SF) in this count.)
15.	Number of Maintenance Outages (MO) which occur from in-service state only	A count of the number of all Maintenance Outages (MO) reported on the GADS Event Report (97). (Since Scheduled Outage Extensions (SE) of Maintenance Outages are considered part of the original Maintenance Outage (MO), they are not included in this count.)

Performance Indexes

1. Planned Outage Factor - POF

$$POF = \frac{\text{Planned Outage Hours}}{\text{Period Hours}} \times 100$$

2. Unplanned Outage Factor - UOF

$$UOF = \frac{\text{Unplanned Outage Hours}}{\text{Period Hours}} \times 100$$

3. Forced Outage Factor - FOF

$$FOF \quad \frac{\text{Unplanned (Forced) Outage Hours}}{\text{Period Hours}} \times 100$$

4. Maintenance Outage Factor - MOF

$$MOF = \frac{\text{Maintenance Outage Hours}}{\text{Period Hours}} \times 100$$

5. Scheduled Outage Factor - SOF

Scheduled Outage Hours

$$\text{SOF} = \frac{}{\text{Period Hours}} \times 100$$

6. Unavailability Factor - UF

$$\text{UF} = \frac{\text{Unavailable Hours}}{\text{Period Hours}} \times 100$$

7. Availability Factor - AF

$$\text{AF} = \frac{\text{Available Hours}}{\text{Period Hours}} \times 100$$

8. Service Factor - SF

$$\text{SF} = \frac{\text{Service Hours}}{\text{Period Hours}} \times 100$$

9. Seasonal Derating Factor - SDF

$$\text{SDF} = \frac{\text{Equivalent Seasonal Derated Hours}}{\text{Period Hours}} \times 100$$

10. Unit Derating Factor - UDF

$$\text{UDF} = \frac{\text{Equivalent Planned Derated Hours} + \text{Equivalent Unplanned Derated Hours}}{\text{Period Hours}} \times 100$$

11. Equivalent Unavailability Factor - EUF

$$\text{EUF} = \frac{\begin{matrix}\text{Planned} \\ \text{Outage Hours}\end{matrix} + \begin{matrix}\text{Unplanned} \\ \text{Outage Hours}\end{matrix} + \begin{matrix}\text{Equiv. Planned} \\ \text{Derated Hours}\end{matrix} + \begin{matrix}\text{Equiv. Unplanned} \\ \text{Derated Hours}\end{matrix}}{\text{Period Hours}} \times 100$$

12. Equivalent Availability Factor - EAF

$$\text{EAF} = \frac{\begin{matrix}\text{Available} \\ \text{Hours}\end{matrix} - \begin{matrix}\text{Equiv. Planned} \\ \text{Derated Hours}\end{matrix} - \begin{matrix}\text{Equiv. Unplanned} \\ \text{Derated Hours}\end{matrix} - \begin{matrix}\text{Equiv. Seasonal} \\ \text{Derated Hours}\end{matrix}}{\text{Period Hours}} \times 100$$

13. Gross Capacity Factor - GCF

$$\text{GCF} = \frac{\text{Gross Actual Generation}}{\text{Period Hours} \times \text{Gross Maximum Capacity}} \times 100$$

14. Net Capacity Factor - NCF

$$\text{NCF} = \frac{\text{Net Actual Generation}}{\text{Period Hours} \ \mathbf{x} \ \text{Net Maximum Capacity}} \ \mathbf{x} \ 100$$

Note: *Net capacity factor calculated using this equation can be negative during a period when the unit is shutdown.*

15. Gross Output Factor - GOF

$$\text{GOF} = \frac{\text{Gross Actual Generation}}{\text{Service Hours} \ \mathbf{x} \ \text{Gross Maximum Capacity}} \ \mathbf{x} \ 100$$

16. Net Output Factor - NOF

$$\text{NOF} = \frac{\text{Net Actual Generation}}{\text{Service Hours} \ \mathbf{x} \ \text{Net Maximum Capacity}} \ \mathbf{x} \ 100$$

17. Forced Outage Rate - FOR

$$\text{FOR} = \frac{\text{Unplanned (Forced) Outage Hours}}{\text{Unplanned (Forced) Outage Hours} \ + \ \text{Service Hours}} \ \mathbf{x} \ 100$$

18. Equivalent Forced Outage Rate - EFOR

$$\text{EFOR} = \frac{\text{Unplanned (Forced) Outage Hours} + \text{Equiv. Unplanned (Forced) Derated Hours}}{\text{Unplanned (Forced) Outage Hours} + \text{Service Hours} + \text{Equiv. Unplanned (Forced) Derated Hours during Reserve Shutdowns (RS) Only}} \ \mathbf{x} \ 100$$

19. Equivalent Forced Outage Rate demand – EFORd

$$\text{EFORd} = \frac{(f^*\text{FOH}) + fp(\text{EFDH})^*100}{\text{SH} + (f^*\text{FOH})}$$

$$fp = (\text{SH}/\text{AH})$$

$$f = \left(1/r + \frac{1}{T}\right) / \left(\frac{1}{r} + \frac{1}{T} + \frac{1}{D}\right)$$

where:

r = Average forced outage duration = (FOH) / (# of FO occurrences)
D = Average demand time = (SH) / (# of unit actual starts)
T = Average reserve shutdown time = (RSH) / (# of unit attempted starts)

20. Average Run Time - ART

$$ART = \frac{\text{Service Hours}}{\text{Actual Unit Starts}}$$

21. Starting Reliability - SR

$$SR = \frac{\text{Actual Unit Starts}}{\text{Attempted Unit Starts}} \times 100$$

Mean Service Time to Outage:

22a. Mean Service Time to Planned Outage - MSTPO

$$MSTPO = \frac{\text{Service Hours}}{\text{Number of Planned Outages}}$$

(which occur from in-service state only)

22b. Mean Service Time to Unplanned Outage - MSTUO

$$MSTUO = \frac{\text{Service Hours}}{\text{Number of Unplanned Outages}}$$

(which occur from in-service state only)

22c. Mean Service Time To Forced Outage - MSTFO

$$MSTFO = \frac{\text{Service Hours}}{\text{Number of (Unplanned) Forced Outages}}$$

(which occur from in-service state only)

22d. Mean Service Time to Maintenance Outage - MSTMO

$$MSTMO = \frac{\text{Service Hours}}{\text{Number of Maintenance Outages}}$$

(which occur from in-service state only)

Mean Outage Duration:

23a. Mean Planned Outage Duration - MPOD

$$MPOD = \frac{\text{Planned Outage Hours}}{\text{Number of Planned Outages}}$$

(which occur from in-service state only)

23b. Mean Unplanned Outage Duration - MUOD

$$MUOD = \frac{\text{Unplanned Outage Hours}}{}$$

Number of Unplanned Outages
(which occur from in-service state only)

23c. Mean Forced Outage Duration - MFOD

$$\text{MFOD} = \frac{\text{Unplanned (Forced) Outage Hours}}{\text{Number of Unplanned (Forced) Outages (which occur from in-service state only)}}$$

23d. Mean Maintenance Outage Duration - MMOD

$$\text{MMOD} = \frac{\text{Maintenance Outage Hours}}{\text{Number of Maintenance Outages (which occur from in-service state only)}}$$

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